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DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 982

[Docket No. FV98–982–1 FIR]

Hazelnuts Grown in Oregon and Washington; Establishment of Interim and Final Free and Restricted Percentages for the 1997–98 Marketing Year

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: The Department of Agriculture (Department) is adopting, as a final rule, without change, the provisions of an interim final rule which established interim and final free and restricted percentages for domestic inshell hazelnuts for the 1997–98 marketing year under the Federal marketing order for hazelnuts grown in Oregon and Washington. The percentages allocate the quantity of domestically produced hazelnuts which may be marketed in the domestic inshell market. The percentages are intended to stabilize the supply of domestic inshell hazelnuts to meet the limited domestic demand for such hazelnuts and provide reasonable returns to producers. This rule was recommended unanimously by the Hazelnut Marketing Board (Board), which is the agency responsible for local administration of the order.

EFFECTIVE DATE: June 22, 1998.

FOR FURTHER INFORMATION CONTACT: Teresa L. Hutchinson, Marketing Specialist, Northwest Marketing Field Office, Fruit and Vegetable Programs, Agricultural Marketing Service, USDA, 1220 SW Third Avenue, Room 369, Portland, OR 97204; telephone: (503) 326–2724, Fax: (503) 326–7440 or George J. Kelhart, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, Room 2525–S, P.O. Box 96456, Washington, DC 20090–6456; telephone: (202) 720–2491, Fax: (202) 205–6632. Small businesses may request information on compliance with this regulation by contacting: Jay Guerber, Marketing Order Administration Branch, Fruit and Vegetable Programs, AMS, USDA, P.O. Box 96456, Room 2525–S, Washington, DC 20090–6456; telephone: (202) 720–2491, Fax: (202) 205–6632.

SUPPLEMENTARY INFORMATION: This final rule is issued under Marketing Agreement No. 115 and Order No. 982 (7 CFR Part 982), both as amended, regulating the handling of hazelnuts grown in Oregon and Washington, hereinafter referred to as the ''order.'' The marketing agreement and order are 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 (Department) is issuing this rule in conformance with Executive Order 12866.

This rule has been reviewed under Executive Order 12988, Civil Justice Reform. It is intended that this action apply to all merchantable hazelnuts handled during the 1997–98 marketing year (July 1, 1997, through June 30, 1998). 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 the Secretary 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, the Secretary 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 the Secretary'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 continues in effect marketing percentages which allocate the quantity of inshell hazelnuts that may be marketed in domestic markets. The Board is required to meet prior to September 20 of each marketing year to compute its marketing policy for that year and compute and announce an inshell trade demand if it determines that volume regulations would tend to effectuate the declared policy of the Act. The Board also computes and announces preliminary free and restricted percentages for that year.

The inshell trade demand is the amount of inshell hazelnuts that handlers may ship to the domestic market throughout the marketing season. The order specifies that the inshell trade demand be computed by averaging the preceding three ''normal'' years'' trade acquisitions of inshell hazelnuts, rounded to the nearest whole number. The Board may increase the three-year average by up to 25 percent, if market conditions warrant an increase. The Board's authority to recommend volume regulations and the computations used to determine released percentages are specified in section 982.40 of the order.

The National Agricultural Statistics Service (NASS) estimated hazelnut production at 40,000 tons for the Oregon and Washington area.

The majority of domestic inshell hazelnuts are marketed in October, November, and December. By November, the marketing season is well under way.

The quantity marketed is broken down into free and restricted percentage portions to make available hazelnuts which may be marketed in domestic inshell markets (free) and hazelnuts which must be exported, shelled or otherwise disposed of (restricted). The preliminary free percentage releases 80 percent of the adjusted inshell trade demand. The preliminary free percentage is expressed as a percentage of the total supply subject to regulation (supply) and is based on the preliminary crop estimate.

At its August 28, 1997, meeting, the Board computed and announced preliminary free and restricted percentages of 8 percent and 92 percent, respectively. The Board used the NASS crop estimate of 40,000 tons. The purpose of releasing only 80 percent of the inshell trade demand under the preliminary percentage was to guard against an underestimate of crop size.

The preliminary free percentage released 3,003 tons of hazelnuts from the 1997 supply for domestic inshell use. The preliminary restricted percentage portion of the 1997 supply for export and kernel markets totaled 34,296 tons.

Under the order, the Board must meet a second time, on or before November 15, to recommend interim final and final percentages. The Board uses current crop estimates to calculate the interim final and final percentages. The interim final percentages are calculated in the same way as the preliminary percentages and release the remaining 20 percent (to total 100 percent of the inshell trade demand) previously computed by the Board. Final free and restricted percentages may release up to an additional 15 percent of the average of the preceding three years' trade acquisitions to provide an adequate carryover into the following season. The final free and restricted percentages must be effective by June 1, at least 30 days prior to the end of the marketing year, June 30. The final free and restricted percentages can be made effective earlier, if recommended by the Board and approved by the Secretary. Revisions in the marketing policy can be made until February 15 of each marketing year, but the inshell trade demand can only be revised upward, consistent with section 982.40(e).

The Board met on November 13, 1997, and reviewed and approved an amended marketing policy. The Board recommended that the three-year average trade acquisition figure of 4,279 tons be increased by 214 tons for market expansion. The Board also recommended the establishment of interim final and final free and restricted percentages. Interim final percentages were recommended at 10 percent free and 90 percent restricted. The interim final percentage made an additional 965 tons of inshell hazelnuts available for the domestic inshell market, including product for market expansion. The interim final marketing percentages were based on the Board's final production estimate (42,000 tons) and released 3,968 tons to the domestic inshell market from the 1997 supply subject to regulation. The interim final restricted percentage resulted in a restricted obligation of 35,173 tons.

The final free and restricted percentages were recommended at 12 percent and 88 percent, respectively. The Board also recommended that the final percentages be effective on April 30, 1997. The established final marketing percentages release for domestic inshell use an additional 642 tons from the supply subject to regulation. Thus, a total of 4,610 tons of inshell hazelnuts will be released from the 1997 supply for domestic inshell use. The final restricted percentage resulted in a restricted obligation of 34,531 tons.

The marketing percentages are based on the Board's production estimates and the following supply and demand information for the 1997–98 marketing year:

			Tons
	Inshell Supply Tons		
(1)	Total production (Board's estimate)		42,000
(2)	Less substandard, farm use (disappearance)		2,860
(3)	Merchantable production (Board's adjusted crop estimate)		39,140
(4)	Plus undeclared carryin as of July 1, 1997, subject to regulation		1
(5)	Supply subject to regulation (Item 3 plus Item 4)		39,141
	Inshell Trade Demand		
(6)	Average trade acquisitions of inshell hazelnuts for three prior years		4,279
(7)	Increase to encourage increased sales (5 percent of Item 6)		214
(8)	Less declared carryin as of July 1, 1996, not subject to regulation		525
(9)	Adjusted Inshell Trade Demand		3,968
(10)	15 percent of the average trade acquisitions of inshell hazelnuts for three prior years (Item 6)		642
(11)	Adjusted Inshell Trade Demand plus 15 percent for carryout (Item 9 plus Item 10)		4,610
	Percentages		
		Free	Restricted
(12)	Interim final percentages (Item 9 divided by Item 5) × 100	10	90
(13)	Final percentages (Item 11 divided by Item 5) × 100	12	88

In addition to complying with the provisions of the order, the Board also considered the Department's 1982 ''Guidelines for Fruit, Vegetable, and Specialty Crop Marketing Orders'' (Guidelines) when making its computations in the marketing policy. This volume control regulation provides a method to collectively limit the supply of inshell hazelnuts available for sale in domestic markets. The Guidelines provide that the domestic inshell market has available a quantity equal to 110 percent of prior years' shipments before secondary market allocations are approved. This provides for plentiful supplies for consumers and for market expansion, while retaining the mechanism for dealing with oversupply situations. At its November 13, 1997, meeting, the Board recommended that an increase of 5 percent (214 tons) for market expansion be included in the inshell trade demand which was used to compute the interim percentages. The established final percentages are based on the final inshell trade demand, and will make available an additional 642 tons for desirable carryout. The total free supply for the 1997–98 marketing year is 5,135 tons of hazelnuts, which is the final trade demand of 4,610 tons plus the declared carryin of 525 tons. This amount is 120 percent of prior years' sales and exceeds the goal of the Guidelines.

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 1,000 producers of hazelnuts in the production area and approximately 23 handlers subject to regulation under the marketing order. Small agricultural producers have been defined by the Small Business Administration (13 CFR 121.601) as those having annual receipts of less than $500,000, and small agricultural service firms are defined as those whose annual receipts are less than $5,000,000. Using these criteria, virtually all of the producers are small agricultural producers and an estimated 20 of the 23 handlers are small agricultural service firms. Thus, the great majority of hazelnut producers and handlers may be classified as small entities.

Board meetings are widely publicized in advance of the meetings and are held in a location central to the production area. The meetings are open to all industry members and other interested persons who are encouraged to participate in the deliberations and voice their opinions on topics under discussion. Thus, Board recommendations can be considered to represent the interests of small business entities in the industry.

Many years of marketing experience led to the development of the current volume control procedures. These procedures have helped the industry solve its marketing problems by keeping inshell supplies in balance with domestic needs. The current volume control procedures fully supply the domestic inshell market, provide for market expansion, and help prevent oversupplies in that market.

Inshell hazelnuts sold to the domestic market provide higher returns to the industry than are obtained from shelling. The inshell market is inelastic and is characterized as having limited demand and being prone to oversupply.

Industry statistics show that total hazelnut production has varied widely over the last 10 years, from a low of 13,000 tons in 1989 to a high of 41,000 tons in 1993, with another record crop of 42,000 tons in 1997. Average production has been around 24,000 tons. While crop size has fluctuated, the volume regulations contribute toward orderly marketing and market stability, and help moderate the variation in returns for all growers and handlers, both large and small. For instance, production in the shortest crop year (1989) was 53 percent of the 10-year average (1987–1996). Production in the biggest crop year (1996) was 170 percent of the 10-year average. The percentage releases provide all handlers with the opportunity to benefit from the most profitable domestic inshell market. That market is available to all handlers, regardless of handler size.

NASS statistics show that the grower price per pound has increased steadily over the last 4 years, from $.28 in 1992 to $.43 in 1996.

The Board discussed the only alternative to this rule which was not to regulate. Without any regulations in effect, the Board believed that the industry would oversupply the inshell domestic market. With the 1997 hazelnut crop the largest in history, the release of 42,000 tons on the domestic inshell market would cause grower returns to decrease drastically, and completely disrupt the market.

While the level of benefits of this rulemaking are difficult to quantify, the stabilizing effects of the volume regulations impact both small and large handlers positively by helping them maintain and expand markets even though hazelnut supplies fluctuate widely from season to season.

Hazelnuts produced under the order comprise virtually all of the hazelnuts produced in the U.S. This production represents, on average, approximately 3 percent of total U.S. tree nut production and approximately 3 percent of the world's hazelnut production.

This volume control regulation provides a method for the U.S. hazelnut industry to limit the supply of domestic inshell hazelnuts available for sale in the U.S. Section 982.40 of the order establishes a procedure and computations for the Board to follow in recommending to the Secretary release of preliminary, interim final, and final quantities of hazelnuts to be released to the free and restricted markets each marketing year. The program results in plentiful supplies for consumers and for market expansion while retaining the mechanism for dealing with oversupply situations.

Currently, U.S. hazelnut production can be successfully allocated between the inshell domestic and secondary markets. One of the best secondary markets for hazelnuts is the export market. Inshell hazelnuts produced under the marketing order compete well in export markets because of quality. Europe, and Germany in particular, is historically the primary world market for U.S. produced inshell hazelnuts, although China was the largest importer in 1996–97. A third market is for shelled hazelnuts sold domestically. Domestically produced kernels generally command a higher price in the domestic market than imported kernels. The industry is continuing its efforts to develop and expand secondary markets, especially the domestic kernel market. Small business entities, both producers and handlers, benefit from the expansion efforts resulting from this program.

There are some reporting, recordkeeping, and other compliance requirements under the order. The reporting and recordkeeping burdens have been accepted by the handlers as necessary for compliance purposes and for developing statistical data for maintenance of the program. The forms require information which is readily available from handler records and which can be provided without data processing equipment or trained statistical staff. As with other marketing order programs, reports and forms are periodically studied to reduce or eliminate duplicate information collection burdens by industry and public sector agencies. This final rule does not change those requirements.

The Department has not identified any relevant Federal rules that duplicate, overlap, or conflict with this regulation.

The interim final rule was published in the **Federal Register** on January 22, 1998 (63 FR 3251). The Board manager mailed information concerning that action to all known industry members, and it was also made available through the Internet by the Office of the Federal Register. That rule provided a 60-day comment period which ended March 23, 1998. No comments were received.

After consideration of all relevant material presented, including the Board's recommendation and other information, it is found that finalizing the interim final rule, without change, as published in the **Federal Register** (63 FR 3251, January 22, 1998), will tend to effectuate the declared policy of the Act.

List of Subjects in 7 CFR Part 982

Filberts, Hazelnuts, Marketing agreements, Nuts, Reporting and recordkeeping requirements.

PART 982—HAZELNUTS GROWN IN OREGON AND WASHINGTON

Accordingly, the interim final rule amending 7 CFR part 982 which was published at 63 FR 3251 on January 22, 1998, is adopted as a final rule without change.

Dated: May 14, 1998.

Robert C. Keeney,

Deputy Administrator, Fruit and Vegetable Programs.

[FR Doc. 98–13524 Filed 5–20–98; 8:45 am]

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DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 1205

[CN–98–002]

1998 Amendment to Cotton Board Rules and Regulations Adjusting Supplemental Assessment on Imports

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Final rule.

SUMMARY: The Agricultural Marketing Service (AMS) is amending the Cotton Board Rules and Regulations by lowering the value assigned to imported cotton for the purpose of calculating supplemental assessments collected for use by the Cotton Research and Promotion Program. This action is required by this regulation on an annual basis to ensure that the assessments collected on imported cotton and the cotton content of imported products remain similar to those paid on domestically produced cotton.

EFFECTIVE DATE: June 22, 1998.

FOR FURTHER INFORMATION CONTACT: Norma McDill, (202) 720–2145.

SUPPLEMENTARY INFORMATION:

Executive Order 12866

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

Executive Order 12988

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

The Cotton Research and Promotion Act provides that administrative proceedings must be exhausted before parties may file suit in court. Under Section 12 of the Act, any person subject to an order may file with the Secretary a petition stating that the order, any provision of the plan, or any obligation imposed in connection with the order is not in accordance with law and requesting a modification of the order or to be exempted therefrom. Such person is afforded the opportunity for a hearing on the petition. After the hearing, the Secretary would rule on the petition. The Act provides that the District Court of the United States in any district in which the person is an inhabitant, or has his principal place of business, has jurisdiction to review the Secretary's ruling, provided a complaint is filed within 20 days from the date of the entry of the ruling.

Regulatory Flexibility Act

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*) AMS has considered the economic impact of this action on small entities and has determined that its implementation will not have a significant economic impact on a substantial number of small businesses.

There are an estimated 16,000 importers who are presently subject to rules and regulations issued pursuant to the Cotton Research and Promotion Order. This rule will affect importers of cotton and cotton-containing products. The majority of these importers are small businesses under the criteria established by the Small Business Administration. This rule will lower the assessments paid by the importers under the Cotton Research and Promotion Order. Even though the assessment would be lowered, the decrease is small and will not significantly affect small businesses.

The current assessment on imported cotton is $0.012412 per kilogram of imported cotton. The amended assessment is $0.011850, a decrease of $0.000562 or a 4.5 percent decrease from the current assessment. From January through December 1997 approximately $20 million was collected at the $0.012412 per kilogram rate. Should the volume of cotton products imported into the U.S. remain at the same level in 1998, one could expect the decreased assessment to generate $19.1 million or a 4.5 percent decrease from 1997.

Paperwork Reduction

In compliance with Office of Management and Budget (OMB) regulations (5 CFR Part 1320) which implement the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*) the information collection requirements contained in the regulation to be amended have been previously approved by OMB and were assigned control number 0581–0093.

Background

The Cotton Research and Promotion Act Amendments of 1990 enacted by Congress under Subtitle G of Title XIX of the Food, Agriculture, Conservation and Trade Act of 1990 on November 28, 1990, contained two provisions that authorized changes in the funding procedures for the Cotton Research and Promotion Program.

These provisions are: (1) The assessment of imported cotton and cotton products; and (2) termination of the right of cotton producers to demand a refund of assessments.

An amended Cotton Research and Promotion Order was approved by producers and importers voting in a referendum held July 17–26, 1991 and the amended Order was published in the **Federal Register** on December 10, 1991, (56 FR 64470). Proposed rules implementing the amended Order were published in the **Federal Register** on December 17, 1991, (56 FR 65450). Implementing rules were published on July 1 and 2, 1992, (57 FR 29181) and (57 FR 29431), respectively.

This rule will decrease the value assigned to imported cotton in the Cotton Board Rules and Regulations (7 CFR 1205.510 (b)(2)). This value is used to calculate supplemental assessments on imported cotton and the cotton content of imported products. Supplemental assessments are the second part of a two-part assessment. The first part of the assessment is levied on the weight of cotton produced or imported at a rate of $1 per bale of cotton which is equivalent to 500 pounds or $1 per 226.8 kilograms of cotton.

Supplemental assessments are levied at a rate of five-tenths of one percent of the value of domestically produced cotton, imported cotton, and the cotton content of imported products. The agency has adopted the practice of assigning the calendar year average price received by U.S. farmers for Upland cotton to represent the value of imported cotton. This is done so that the assessment on domestically produced cotton and the assessment on imported cotton and the cotton content of imported products remain similar. The source for the average price statistic is ''Agricultural Prices'', a publication of the National Agricultural Statistics Service (NASS) of the Department of Agriculture. Use of the average price figure in the calculation of supplemental assessments on imported cotton and the cotton content of imported products yields an assessment that approximates assessments paid on domestically produced cotton in the prior calendar year.

The current value of imported cotton as published in the **Federal Register** (62 FR 46412) on September 2, 1997, for the purpose of calculating supplemental assessments on imported cotton is $1.6005 per kilogram. This number was calculated using the annual average price received by farmers for Upland cotton during the calendar year 1996 which was $0.726 per pound and multiplying by the conversion factor

2.2046. Using the Average Price Received by U.S. Farmers for Upland Cotton for the calendar year 1997, which is $0.675 per pound, the new value of imported cotton is $1.4881 per kilogram. The amended value is $0.1124 per kilogram less than the previous value.

An example of the complete assessment formula and how the various figures are obtained is as follows:

One bale is equal to 500 pounds.
One kilogram equals 2.2046 pounds.
One pound equals 0.453597 kilograms.

One Dollar Per Bale Assessment Converted to Kilograms

A 500 pound bale equals 226.8 kg. (500 × .453597).
$1 per bale assessment equals $0.002000 per pound (1÷500)
or $0.004409 per kg. (1÷226.8).

Supplemental Assessment of 5/10 of One Percent of the Value of the Cotton Converted to Kilograms

The 1997 calendar year average price received by producers for Upland cotton is $0.675 per pound or $1.4881 per kg. (0.675 × 2.2046)=1.4881.
Five tenths of one percent of the average price in kg. equals $0.007441 per kg. (1.4881 × .005).

Total Assessment

The total assessment per kilogram of raw cotton is obtained by adding the $1 per bale equivalent assessment of $0.004409 per kg. and the supplemental assessment $0.007441 per kg. which equals $0.011850 per kg.

The current assessment on imported cotton is $0.012412 per kilogram of imported cotton. The amended assessment is $0.011850, a decrease of $0.000562 per kilogram. This decrease reflects the decrease in the Average Price of Upland Cotton Received by U.S. Farmers during the period January through December 1997.

Since the value of cotton is the basis of the supplemental assessment calculation and the figures shown in the right hand column of the Import Assessment Table 1205.510(b)(3) are a result of such a calculation, the figures in this table have been revised. These figures indicate the total assessment per kilogram due for each Harmonized Tariff Schedule (HTS) number subject to assessment.

Eight HTS numbers subject to assessment pursuant to this regulation and found in the assessment table have been changed. In order to maintain consistency between the HTS and the assessment table, the changes to these eight numbers have been incorporated into the assessment table. The last two digits of these numbers were changed to provide for statistical reporting purposes and involve no physical change to the products they represent. Therefore, the assessment rate is not affected by the change. The assessment rate for each of the eight numbers has been applied to each of the new replacement numbers in the assessment table. The following table represents the changes:

Old No.	New No.	Conversion factor	Assessment cents/kg.
5208523040	5208523045	1.1455	1.3574
5208524040	5208524045	1.1455	1.3574
5208524060	5208524065	1.1455	1.3574
5208592020	5208592025	1.1455	1.3574
5208592090	5208592095	1.1455	1.3574
5209516030	5209516035	1.1455	1.3574
5209590020	5209590025	1.1455	1.3574
5211590020	5211590025	0.6873	0.8145

A proposed rule with a request for comments was published in the **Federal Register** (63 FR 15336) on March 31, 1998. No comments were received during the comment period (March 31 through April 30, 1998).

List of Subjects in 7 CFR Part 1205

Advertising, Agricultural research, Cotton, Marketing agreements, Reporting and recordkeeping requirements.

For the reasons set forth in the preamble, 7 CFR Part 1205 is amended as follows:

PART 1205—COTTON RESEARCH AND PROMOTION

1. The authority citation for Part 1205 continues to read as follows:

Authority: 7 U.S.C. 2101–2118.

2. In § 1205.510, paragraphs (b)(2) and the table in paragraph (b)(3)(ii) are revised to read as follows:

§ 1205.510 Levy of assessments.

* * * * *

(b) * * *

(2) The 12-month average of monthly average prices received by U.S. farmers will be calculated annually. Such average will be used as the value of imported cotton for the purpose of levying the supplemental assessment on imported cotton and will be expressed in kilograms. The value of imported cotton for the purpose of levying this supplemental assessment is $1.4881 per kilogram.

(3) * * *

(ii) * * *

IMPORT ASSESSMENT TABLE

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/ kg.
5201000500	0	1.185
5201001200	0	1.185
5201001400	0	1.185
5201001800	0	1.185
5201002200	0	1.185
5201002400	0	1.185
5201002800	0	1.185
5201003400	0	1.185

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/ kg.
5201003800	0	1.185
5204110000	1.1111	1.3167
5204200000	1.1111	1.3167
5205111000	1.1111	1.3167
5205112000	1.1111	1.3167
5205121000	1.1111	1.3167
5205122000	1.1111	1.3167
5205131000	1.1111	1.3167
5205132000	1.1111	1.3167
5205141000	1.1111	1.3167
5205210020	1.1111	1.3167
5205210090	1.1111	1.3167
5205220020	1.1111	1.3167
5205220090	1.1111	1.3167
5205230020	1.1111	1.3167
5205230090	1.1111	1.3167
5205240020	1.1111	1.3167
5205240090	1.1111	1.3167
5205310000	1.1111	1.3167
5205320000	1.1111	1.3167
5205330000	1.1111	1.3167
5205340000	1.1111	1.3167
5205410020	1.1111	1.3167

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/kg.
5205410090	1.1111	1.3167
5205420020	1.1111	1.3167
5205420090	1.1111	1.3167
5205440020	1.1111	1.3167
5205440090	1.1111	1.3167
5206120000	0.5556	0.6584
5206130000	0.5556	0.6584
5206140000	0.5556	0.6584
5206220000	0.5556	0.6584
5206230000	0.5556	0.6584
5206240000	0.5556	0.6584
5206310000	0.5556	0.6584
5207100000	1.1111	1.3167
5207900000	0.5556	0.6584
5208112020	1.1455	1.3574
5208112040	1.1455	1.3574
5208112090	1.1455	1.3574
5208114020	1.1455	1.3574
5208114060	1.1455	1.3574
5208114090	1.1455	1.3574
5208118090	1.1455	1.3574
5208124020	1.1455	1.3574
5208124040	1.1455	1.3574
5208124090	1.1455	1.3574
5208126020	1.1455	1.3574
5208126040	1.1455	1.3574
5208126060	1.1455	1.3574
5208126090	1.1455	1.3574
5208128020	1.1455	1.3574
5208128090	1.1455	1.3574
5208130000	1.1455	1.3574
5208192020	1.1455	1.3574
5208192090	1.1455	1.3574
5208194020	1.1455	1.3574
5208194090	1.1455	1.3574
5208196020	1.1455	1.3574
5208196090	1.1455	1.3574
5208224040	1.1455	1.3574
5208224090	1.1455	1.3574
5208226020	1.1455	1.3574
5208226060	1.1455	1.3574
5208228020	1.1455	1.3574
5208230000	1.1455	1.3574
5208292020	1.1455	1.3574
5208292090	1.1455	1.3574
5208294090	1.1455	1.3574
5208296090	1.1455	1.3574
5208298020	1.1455	1.3574
5208312000	1.1455	1.3574
5208321000	1.1455	1.3574
5208323020	1.1455	1.3574
5208323040	1.1455	1.3574
5208323090	1.1455	1.3574
5208324020	1.1455	1.3574
5208324040	1.1455	1.3574
5208325020	1.1455	1.3574
5208330000	1.1455	1.3574
5208392020	1.1455	1.3574
5208392090	1.1455	1.3574
5208394090	1.1455	1.3574
5208396090	1.1455	1.3574
5208398020	1.1455	1.3574
5208412000	1.1455	1.3574
5208416000	1.1455	1.3574
5208418000	1.1455	1.3574
5208421000	1.1455	1.3574
5208423000	1.1455	1.3574
5208424000	1.1455	1.3574
5208425000	1.1455	1.3574

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/kg.
5208430000	1.1455	1.3574
5208492000	1.1455	1.3574
5208494020	1.1455	1.3574
5208494090	1.1455	1.3574
5208496010	1.1455	1.3574
5208496090	1.1455	1.3574
5208498090	1.1455	1.3574
5208512000	1.1455	1.3574
5208516060	1.1455	1.3574
5208518090	1.1455	1.3574
5208523020	1.1455	1.3574
5208523045	1.1455	1.3574
5208523090	1.1455	1.3574
5208524020	1.1455	1.3574
5208524045	1.1455	1.3574
5208524065	1.1455	1.3574
5208525020	1.1455	1.3574
5208530000	1.1455	1.3574
5208592025	1.1455	1.3574
5208592095	1.1455	1.3574
5208594090	1.1455	1.3574
5208596090	1.1455	1.3574
5209110020	1.1455	1.3574
5209110035	1.1455	1.3574
5209110090	1.1455	1.3574
5209120020	1.1455	1.3574
5209120040	1.1455	1.3574
5209190020	1.1455	1.3574
5209190040	1.1455	1.3574
5209190060	1.1455	1.3574
5209190090	1.1455	1.3574
5209210090	1.1455	1.3574
5209220020	1.1455	1.3574
5209220040	1.1455	1.3574
5209290040	1.1455	1.3574
5209290090	1.1455	1.3574
5209313000	1.1455	1.3574
5209316020	1.1455	1.3574
5209316035	1.1455	1.3574
5209316050	1.1455	1.3574
5209316090	1.1455	1.3574
5209320020	1.1455	1.3574
5209320040	1.1455	1.3574
5209390020	1.1455	1.3574
5209390040	1.1455	1.3574
5209390060	1.1455	1.3574
5209390080	1.1455	1.3574
5209390090	1.1455	1.3574
5209413000	1.1455	1.3574
5209416020	1.1455	1.3574
5209416040	1.1455	1.3574
5209420020	1.0309	1.2216
5209420040	1.0309	1.2216
5209430030	1.1455	1.3574
5209430050	1.1455	1.3574
5209490020	1.1455	1.3574
5209490090	1.1455	1.3574
5209516035	1.1455	1.3574
5209516050	1.1455	1.3574
5209520020	1.1455	1.3574
5209590025	1.1455	1.3574
5209590040	1.1455	1.3574
5209590090	1.1455	1.3574
5210114020	0.6873	0.8145
5210114040	0.6873	0.8145
5210116020	0.6873	0.8145
5210116040	0.6873	0.8145
5210116060	0.6873	0.8145
5210118020	0.6873	0.8145

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/kg.
5210120000	0.6873	0.8145
5210192090	0.6873	0.8145
5210214040	0.6873	0.8145
5210216020	0.6873	0.8145
5210216060	0.6873	0.8145
5210218020	0.6873	0.8145
5210314020	0.6873	0.8145
5210314040	0.6873	0.8145
5210316020	0.6873	0.8145
5210318020	0.6873	0.8145
5210414000	0.6873	0.8145
5210416000	0.6873	0.8145
5210418000	0.6873	0.8145
5210498090	0.6873	0.8145
5210514040	0.6873	0.8145
5210516020	0.6873	0.8145
5210516040	0.6873	0.8145
5210516060	0.6873	0.8145
5211110090	0.6873	0.8145
5211120020	0.6873	0.8145
5211190020	0.6873	0.8145
5211190060	0.6873	0.8145
5211210025	0.4165	0.4936
5211210035	0.4165	0.4936
5211210050	0.6873	0.8145
5211290090	0.6873	0.8145
5211320020	0.6873	0.8145
5211390040	0.6873	0.8145
5211390060	0.6873	0.8145
5211490020	0.6873	0.8145
5211490090	0.6873	0.8145
5211590025	0.6873	0.8145
5212146090	0.9164	1.0859
5212156020	0.9164	1.0859
5212216090	0.9164	1.0859
5509530030	0.5556	0.6584
5509530060	0.5556	0.6584
5513110020	0.4009	0.4751
5513110040	0.4009	0.4751
5513110060	0.4009	0.4751
5513110090	0.4009	0.4751
5513120000	0.4009	0.4751
5513130020	0.4009	0.4751
5513210020	0.4009	0.4751
5513310000	0.4009	0.4751
5514120020	0.4009	0.4751
5516420060	0.4009	0.4751
5516910060	0.4009	0.4751
5516930090	0.4009	0.4751
5601210010	1.1455	1.3574
5601210090	1.1455	1.3574
5601300000	1.1455	1.3574
5602109090	0.5727	0.6786
5602290000	1.1455	1.3574
5602906000	0.526	0.6233
5604900000	0.5556	0.6584
5607902000	0.8889	1.0533
5608901000	1.1111	1.3167
5608902300	1.1111	1.3167
5609001000	1.1111	1.3167
5609004000	0.5556	0.6584
5701104000	0.0556	0.0659
5701109000	0.1111	0.1317
5701901010	1.0444	1.2376
5702109020	1.1	1.3035
5702312000	0.0778	0.0922
5702411000	0.0722	0.0856
5702412000	0.0778	0.0922
5702421000	0.0778	0.0922

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/kg.
5702913000	0.0889	0.1053
5702991010	1.1111	1.3167
5702991090	1.1111	1.3167
5703900000	0.4489	0.5319
5801210000	1.1455	1.3574
5801230000	1.1455	1.3574
5801250010	1.1455	1.3574
5801250020	1.1455	1.3574
5801260020	1.1455	1.3574
5802190000	1.1455	1.3574
5802300030	0.5727	0.6786
5804291000	1.1455	1.3574
5806200010	0.3534	0.4188
5806200090	0.3534	0.4188
5806310000	1.1455	1.3574
5806400000	0.4296	0.5091
5808107000	0.5727	0.6786
5808900010	0.5727	0.6786
5811002000	1.1455	1.3574
6001106000	1.1455	1.3574
6001210000	0.8591	1.018
6001220000	0.2864	0.3394
6001910010	0.8591	1.018
6001910020	0.8591	1.018
6001920020	0.2864	0.3394
6001920030	0.2864	0.3394
6001920040	0.2864	0.3394
6002203000	0.8681	1.0287
6002206000	0.2894	0.3429
6002420000	0.8681	1.0287
6002430010	0.2894	0.3429
6002430080	0.2894	0.3429
6002921000	1.1574	1.3715
6002930040	0.1157	0.1371
6002930080	0.1157	0.1371
6101200010	1.0094	1.1961
6101200020	1.0094	1.1961
6102200010	1.0094	1.1961
6102200020	1.0094	1.1961
6103421020	0.8806	1.0435
6103421040	0.8806	1.0435
6103421050	0.8806	1.0435
6103421070	0.8806	1.0435
6103431520	0.2516	0.2981
6103431540	0.2516	0.2981
6103431550	0.2516	0.2981
6103431570	0.2516	0.2981
6104220040	0.9002	1.0667
6104220060	0.9002	1.0667
6104320000	0.9207	1.091
6104420010	0.9002	1.0667
6104420020	0.9002	1.0667
6104520010	0.9312	1.1035
6104520020	0.9312	1.1035
6104622006	0.8806	1.0435
6104622011	0.8806	1.0435
6104622016	0.8806	1.0435
6104622021	0.8806	1.0435
6104622026	0.8806	1.0435
6104622028	0.8806	1.0435
6104622030	0.8806	1.0435
6104622060	0.8806	1.0435
6104632006	0.3774	0.4472
6104632011	0.3774	0.4472
6104632026	0.3774	0.4472
6104632028	0.3774	0.4472
6104632030	0.3774	0.4472
6104632060	0.3774	0.4472
6104692030	0.3858	0.4572

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/kg.
6105100010	0.985	1.1672
6105100020	0.985	1.1672
6105100030	0.985	1.1672
6105202010	0.3078	0.3647
6105202030	0.3078	0.3647
6106100010	0.985	1.1672
6106100020	0.985	1.1672
6106100030	0.985	1.1672
6106202010	0.3078	0.3647
6106202030	0.3078	0.3647
6107110010	1.1322	1.3417
6107110020	1.1322	1.3417
6107120010	0.5032	0.5963
6107210010	0.8806	1.0435
6107220015	0.3774	0.4472
6107220025	0.3774	0.4472
6107910040	1.2581	1.4908
6108210010	1.2445	1.4747
6108210020	1.2445	1.4747
6108310010	1.1201	1.3273
6108310020	1.1201	1.3273
6108320010	0.2489	0.2949
6108320015	0.2489	0.2949
6108320025	0.2489	0.2949
6108910005	1.2445	1.4747
6108910015	1.2445	1.4747
6108910025	1.2445	1.4747
6108910030	1.2445	1.4747
6108920030	0.2489	0.2949
6109100005	0.9956	1.1798
6109100007	0.9956	1.1798
6109100009	0.9956	1.1798
6109100012	0.9956	1.1798
6109100014	0.9956	1.1798
6109100018	0.9956	1.1798
6109100023	0.9956	1.1798
6109100027	0.9956	1.1798
6109100037	0.9956	1.1798
6109100040	0.9956	1.1798
6109100045	0.9956	1.1798
6109100060	0.9956	1.1798
6109100065	0.9956	1.1798
6109100070	0.9956	1.1798
6109901007	0.3111	0.3687
6109901009	0.3111	0.3687
6109901049	0.3111	0.3687
6109901050	0.3111	0.3687
6109901060	0.3111	0.3687
6109901065	0.3111	0.3687
6109901090	0.3111	0.3687
6110202005	1.1837	1.4027
6110202010	1.1837	1.4027
6110202015	1.1837	1.4027
6110202020	1.1837	1.4027
6110202025	1.1837	1.4027
6110202030	1.1837	1.4027
6110202035	1.1837	1.4027
6110202040	1.1574	1.3715
6110202045	1.1574	1.3715
6110202065	1.1574	1.3715
6110202075	1.1574	1.3715
6110909022	0.263	0.3117
6110909024	0.263	0.3117
6110909030	0.3946	0.4676
6110909040	0.263	0.3117
6110909042	0.263	0.3117
6111201000	1.2581	1.4908
6111202000	1.2581	1.4908
6111203000	1.0064	1.1926

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/kg.
6111205000	1.0064	1.1926
6111206010	1.0064	1.1926
6111206020	1.0064	1.1926
6111206030	1.0064	1.1926
6111206040	1.0064	1.1926
6111305020	0.2516	0.2981
6111305040	0.2516	0.2981
6112110050	0.7548	0.8944
6112120010	0.2516	0.2981
6112120030	0.2516	0.2981
6112120040	0.2516	0.2981
6112120050	0.2516	0.2981
6112120060	0.2516	0.2981
6112390010	1.1322	1.3417
6112490010	0.9435	1.118
6114200005	0.9002	1.0667
6114200010	0.9002	1.0667
6114200015	0.9002	1.0667
6114200020	1.286	1.5239
6114200040	0.9002	1.0667
6114200046	0.9002	1.0667
6114200052	0.9002	1.0667
6114200060	0.9002	1.0667
6114301010	0.2572	0.3048
6114301020	0.2572	0.3048
6114303030	0.2572	0.3048
6115198010	1.0417	1.2344
6115929000	1.0417	1.2344
6115936020	0.2315	0.2743
6116101300	0.3655	0.4331
6116101720	0.8528	1.0106
6116926420	1.0965	1.2994
6116926430	1.2183	1.4437
6116926440	1.0965	1.2994
6116928800	1.0965	1.2994
6117809510	0.9747	1.155
6117809540	0.3655	0.4331
6201121000	0.948	1.1234
6201122010	0.8953	1.0609
6201122050	0.6847	0.8114
6201122060	0.6847	0.8114
6201134030	0.2633	0.312
6201921000	0.9267	1.0981
6201921500	1.1583	1.3726
6201922010	1.0296	1.2201
6201922021	1.2871	1.5252
6201922031	1.2871	1.5252
6201922041	1.2871	1.5252
6201922051	1.0296	1.2201
6201922061	1.0296	1.2201
6201931000	0.3089	0.366
6201933511	0.2574	0.305
6201933521	0.2574	0.305
6201999060	0.2574	0.305
6202121000	0.9372	1.1106
6202122010	1.1064	1.3111
6202122025	1.3017	1.5425
6202122050	0.8461	1.0026
6202122060	0.8461	1.0026
6202134005	0.2664	0.3157
6202134020	0.333	0.3946
6202921000	1.0413	1.2339
6202921500	1.0413	1.2339
6202922026	1.3017	1.5425
6202922061	1.0413	1.2339
6202922071	1.0413	1.2339
6202931000	0.3124	0.3702
6202935011	0.2603	0.3085
6202935021	0.2603	0.3085

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/kg.
6203122010	0.1302	0.1543
6203221000	1.3017	1.5425
6203322010	1.2366	1.4654
6203322040	1.2366	1.4654
6203332010	0.1302	0.1543
6203392010	1.1715	1.3882
6203399060	0.2603	0.3085
6203422010	0.9961	1.1804
6203422025	0.9961	1.1804
6203422050	0.9961	1.1804
6203422090	0.9961	1.1804
6203424005	1.2451	1.4754
6203424010	1.2451	1.4754
6203424015	0.9961	1.1804
6203424020	1.2451	1.4754
6203424025	1.2451	1.4754
6203424030	1.2451	1.4754
6203424035	1.2451	1.4754
6203424040	0.9961	1.1804
6203424045	0.9961	1.1804
6203424050	0.9238	1.0947
6203424055	0.9238	1.0947
6203424060	0.9238	1.0947
6203431500	0.1245	0.1475
6203434010	0.1232	0.146
6203434020	0.1232	0.146
6203434030	0.1232	0.146
6203434040	0.1232	0.146
6203498045	0.249	0.2951
6204132010	0.1302	0.1543
6204192000	0.1302	0.1543
6204198090	0.2603	0.3085
6204221000	1.3017	1.5425
6204223030	1.0413	1.2339
6204223040	1.0413	1.2339
6204223050	1.0413	1.2339
6204223060	1.0413	1.2339
6204223065	1.0413	1.2339
6204292040	0.3254	0.3856
6204322010	1.2366	1.4654
6204322030	1.0413	1.2339
6204322040	1.0413	1.2339
6204423010	1.2728	1.5083
6204423030	0.9546	1.1312
6204423040	0.9546	1.1312
6204423050	0.9546	1.1312
6204423060	0.9546	1.1312
6204522010	1.2654	1.4995
6204522030	1.2654	1.4995
6204522040	1.2654	1.4995
6204522070	1.0656	1.2627
6204522080	1.0656	1.2627
6204533010	0.2664	0.3157
6204594060	0.2664	0.3157
6204622010	0.9961	1.1804
6204622025	0.9961	1.1804
6204622050	0.9961	1.1804
6204624005	1.2451	1.4754
6204624010	1.2451	1.4754
6204624020	0.9961	1.1804
6204624025	1.2451	1.4754
6204624030	1.2451	1.4754
6204624035	1.2451	1.4754
6204624040	1.2451	1.4754
6204624045	0.9961	1.1804
6204624050	0.9961	1.1804
6204624055	0.9854	1.1677
6204624060	0.9854	1.1677
6204624065	0.9854	1.1677

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/kg.
6204633510	0.2546	0.3017
6204633530	0.2546	0.3017
6204633532	0.2437	0.2888
6204633540	0.2437	0.2888
6204692510	0.249	0.2951
6204692540	0.2437	0.2888
6204699044	0.249	0.2951
6204699046	0.249	0.2951
6204699050	0.249	0.2951
6205202015	0.9961	1.1804
6205202020	0.9961	1.1804
6205202025	0.9961	1.1804
6205202030	0.9961	1.1804
6205202035	1.1206	1.3279
6205202046	0.9961	1.1804
6205202050	0.9961	1.1804
6205202060	0.9961	1.1804
6205202065	0.9961	1.1804
6205202070	0.9961	1.1804
6205202075	0.9961	1.1804
6205302010	0.3113	0.3689
6205302030	0.3113	0.3689
6205302040	0.3113	0.3689
6205302050	0.3113	0.3689
6205302070	0.3113	0.3689
6205302080	0.3113	0.3689
6206100040	0.1245	0.1475
6206303010	0.9961	1.1804
6206303020	0.9961	1.1804
6206303030	0.9961	1.1804
6206303040	0.9961	1.1804
6206303050	0.9961	1.1804
6206303060	0.9961	1.1804
6206403010	0.3113	0.3689
6206403030	0.3113	0.3689
6206900040	0.249	0.2951
6207110000	1.0852	1.286
6207199010	0.3617	0.4286
6207210010	1.1085	1.3136
6207210030	1.1085	1.3136
6207220000	0.3695	0.4379
6207911000	1.1455	1.3574
6207913010	1.1455	1.3574
6207913020	1.1455	1.3574
6208210010	1.0583	1.2541
6208210020	1.0583	1.2541
6208220000	0.1245	0.1475
6208911010	1.1455	1.3574
6208911020	1.1455	1.3574
6208913010	1.1455	1.3574
6209201000	1.1577	1.3719
6209203000	0.9749	1.1553
6209205030	0.9749	1.1553
6209205035	0.9749	1.1553
6209205040	1.2186	1.444
6209205045	0.9749	1.1553
6209205050	0.9749	1.1553
6209303020	0.2463	0.2919
6209303040	0.2463	0.2919
6210109010	0.2291	0.2715
6210403000	0.0391	0.0463
6210405020	0.4556	0.5399
6211111010	0.1273	0.1509
6211111020	0.1273	0.1509
6211118010	1.1455	1.3574
6211118020	1.1455	1.3574
6211320007	0.8461	1.0026
6211320010	1.0413	1.2339
6211320015	1.0413	1.2339

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/kg.
6211320030	0.9763	1.1569
6211320060	0.9763	1.1569
6211320070	0.9763	1.1569
6211330010	0.3254	0.3856
6211330030	0.3905	0.4627
6211330035	0.3905	0.4627
6211330040	0.3905	0.4627
6211420010	1.0413	1.2339
6211420020	1.0413	1.2339
6211420025	1.1715	1.3882
6211420060	1.0413	1.2339
6211420070	1.1715	1.3882
6211430010	0.2603	0.3085
6211430030	0.2603	0.3085
6211430040	0.2603	0.3085
6211430050	0.2603	0.3085
6211430060	0.2603	0.3085
6211430066	0.2603	0.3085
6212105020	0.2412	0.2858
6212109010	0.9646	1.1431
6212109020	0.2412	0.2858
6212200020	0.3014	0.3572
6212900030	0.1929	0.2286
6213201000	1.1809	1.3994
6213202000	1.0628	1.2594
6213901000	0.4724	0.5598
6214900010	0.9043	1.0716
6216000800	0.2351	0.2786
6216001720	0.6752	0.8001
6216003800	1.2058	1.4289
6216004100	1.2058	1.4289
6217109510	1.0182	1.2066
6217109530	0.2546	0.3017
6301300010	0.8766	1.0388
6301300020	0.8766	1.0388
6302100010	1.1689	1.3851
6302215010	0.8182	0.9696
6302215020	0.8182	0.9696
6302217010	1.1689	1.3851
6302217020	1.1689	1.3851
6302217050	1.1689	1.3851
6302219010	0.8182	0.9696
6302219020	0.8182	0.9696
6302219050	0.8182	0.9696
6302222010	0.4091	0.4848
6302222020	0.4091	0.4848
6302313010	0.8182	0.9696
6302313050	1.1689	1.3851
6302315050	0.8182	0.9696
6302317010	1.1689	1.3851
6302317020	1.1689	1.3851
6302317040	1.1689	1.3851
6302317050	1.1689	1.3851
6302319010	0.8182	0.9696
6302319040	0.8182	0.9696
6302319050	0.8182	0.9696
6302322020	0.4091	0.4848
6302322040	0.4091	0.4848
6302402010	0.9935	1.1773
6302511000	0.5844	0.6925
6302512000	0.8766	1.0388
6302513000	0.5844	0.6925
6302514000	0.8182	0.9696
6302600010	1.1689	1.3851
6302600020	1.052	1.2466
6302600030	1.052	1.2466
6302910005	1.052	1.2466
6302910015	1.1689	1.3851
6302910025	1.052	1.2466

IMPORT ASSESSMENT TABLE—Continued

[Raw cotton fiber]

HTS No.	Conv. fact.	Cents/ kg.
6302910035	1.052	1.2466
6302910045	1.052	1.2466
6302910050	1.052	1.2466
6302910060	1.052	1.2466
6303110000	0.9448	1.1196
6303910000	0.6429	0.7618
6304111000	1.0629	1.2595
6304190500	1.052	1.2466
6304191000	1.1689	1.3851
6304191500	0.4091	0.4848
6304192000	0.4091	0.4848
6304910020	0.9351	1.1081
6304920000	0.9351	1.1081
6505901540	1.181	1.3995
6505902060	0.9935	1.1773
6505902545	0.5844	0.6925

* * * * *

Dated: May 15, 1998.

Mary E. Atienza,

Deputy Administrator, Cotton Programs.

[FR Doc. 98–13525 Filed 5–20–98; 8:45 am]

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DEPARTMENT OF JUSTICE

Immigration and Naturalization Service

8 CFR Parts 3, 240, 245, 274a and 299

[INS NO. 1893–97; AG Order No. 2154–98]

RIN 1115–AF04

Adjustment of Status for Certain Nationals of Nicaragua and Cuba

AGENCY: Immigration and Naturalization Service, Justice, and Executive Office for Immigration Review, Justice.

ACTION: Interim rule with request for comments.

SUMMARY: This interim rule implements section 202 of the Nicaragua Adjustment and Central American Relief Act (NACARA) by establishing procedures for certain nationals of Nicaragua and Cuba who have been residing in the United States to become lawful permanent residents of this country. This rule allows them to obtain lawful permanent resident status without applying for an immigrant visa at a United States consulate abroad and waives many of the usual requirements for this benefit.

DATES: *Effective date:* This interim rule is effective June 22, 1998.

Comment date: Comments must be submitted on or before July 20, 1998.

ADDRESSES: Please submit written comments, original and two copies,to the Director, Policy Directives and Instructions Branch, Immigration and Naturalization Service, 425 I Street NW, Room 5307, Washington, DC 20536. To ensure proper handling, please reference INS No. 1893–97 on your correspondence. Comments are available for public inspection at the above address by calling (202) 514–3048 to arrange for an appointment.

FOR FURTHER INFORMATION CONTACT: *For matters relating to the Immigration and Naturalization Service*—Suzy Nguyen, Adjudications Officer, Office of Adjudications, Immigration and Naturalization Service, 425 I Street NW, Room 3214, Washington, DC 20536, telephone (202) 514–5014; *For matters relating to the Executive Office for Immigration Review*—Margaret M. Philbin, General Counsel, Executive Office for Immigration Review, 5107 Leesbury Pike, Suite 2400, Falls Church, VA 22041, telephone (703) 305–0470.

SUPPLEMENTARY INFORMATION:

How Does Section 202 of NACARA Affect Nicaraguan and Cuban Nationals?

The Nicaraguan Adjustment and Central American Relief Act (NACARA), enacted as title II of the District of Columbia Appropriations Act, 1998, Pub. L. 105–100 (111 Stat. 2160, 2193), was signed into law on November 19, 1997. As amended, section 202 of NACARA allows certain Nicaragua and Cuban nationals who are physically present in the United States to adjust status to that of lawful permanent resident. In order to be eligible for benefits under NACARA, an applicant must be a national of Nicaragua or Cuba; must be admissible to the United States under all provisions of section 212(a) of the Immigration and Nationality Act (the Act), other than those provisions specifically excepted by NACARA; must have been physically present in the United States for a continuous period beginning not later than December 1, 1995, and ending not earlier than the date the application for adjustment is filed (not counting absences totaling 180 days or less); and must properly file an application before April 1, 2000. In addition, certain family members of NACARA beneficiaries are also eligible for adjustment of status under NACARA.

What Are the Benefits of NACARA?

An alien seeking adjustment of status under NACARA is not subject to a number of the requirements to which aliens seeking adjustment under section 245 of the Act may be subject.

First, a NACARA applicant is not required to have been inspected and admitted or paroled into the United States.

Second, a NACARA applicant is not subject to any of the barriers to adjustment contained in section 245(c) of the Act (e.g., the bars against aliens who have accepted or continued in unauthorized employment, aliens who remained in the United States longer than authorized, and aliens admitted as crewmen, in transmit without visa, or under the visa waiver pilot program). Consequently, an alien who would otherwise be ineligible under section 245(c) may apply for adjustment under NACARA.

Third, NACARA applicants are not subject to the immigrant visa preference system requirements contained in sections 201 and 202 of the Act. Hence, neither the worldwide quota restrictions nor the per-country quota restrictions apply.

Fourth, applicants need not demonstrate that they are not inadmissible under paragraphs (4), (5), (6)(A), (7)(A), and (9)(B) of section 212(a) of the Act in order to adjust status under section 202 of Public Law 105–100. Accordingly, NACARA allows an otherwise qualified applicant to adjust status under NACARA notwithstanding inadmissibility for likelihood of becoming a public charge, for failure to obtain a labor certification, for failure to meet certain requirements applicable to foreign-trained physicians, for failure to meet certain standards for foreign health-care workers, for entering or remaining in the country illegally, for violating documentary requirements relating to entry as an immigrant, or for accruing more than 180 days of unlawful presence prior to the alien's last departure or removal.

Fifth, unlike those seeking to adjust status under other provisions of law, a NACARA applicant who has been paroled into the United States and is now in exclusion or removal proceedings before an immigration judge is not barred from filing an application for adjustment of status under the provisions of NACARA while in such proceedings.

What Are the NACARA Requirements Regarding Continuous Physical Presence in the United States

Under the terms of NACARA, eligible applicants must have been physically present in the United States continuously since December 1, 1995. However, they may have been outside of the United States for periods not to exceed 180 days in the aggregate between December 1, 1995, and the date of adjustment of status. A NACARA applicant shall not be considered to

have failed to maintain continuous physical presence in the United States by reason of any absences for periods that do not exceed 180 days in the aggregate. Furthermore, the 180-day cumulative period shall be tolled during an absence authorized pursuant to issuance of an Authorization for Parole of an alien into the United States (Form I–512).

How Can a NACARA Applicant Prove Continuous Physical Presence in the United States?

A NACARA applicant must establish two aspects of physical presence in the United States: commencement on or prior to December 1, 1995, and continuity since that date.

Under section 202(b)(2)(A) of Pub. L. 105–100, as amended, an applicant may prove commencement of continuous physical presence in the United States by demonstrating that on or before December 1, 1995, he or she:

(i) Applied to the Attorney General for asylum;

(ii) was issued an order to show cause under section 242 or 242B of the Immigration and Nationality Act (as in effect prior to April 1, 1997);

(iii) was placed in exclusion proceedings under section 236 of such Act (as in effect prior to April 1, 1997);

(iv) Applied for adjustment of status under section 245 of such Act;

(v) Applied to the Attorney General for employment authorization;

(vi) Performed service, or engaged in a trade or business, within the United States which is evidenced by records maintained by the Commissioner of Social Security; or

(vii) Applied for any other benefit under the Immigration and Nationality Act by means of an application establishing the alien's presence in the United States prior to December 1, 1995.

Normally, such demonstration will be made through submission of a photocopy of a Government-issued document. In some cases, the alien may submit other evidence demonstrating one or more of the above actions, which may be verified through Government records.

Section 202(b)(2)(B) of NACARA also permits, but does not require, the Attorney General to provide by regulation for additional methods by which an applicant could prove commencement of continuous physical presence in the United States. The Department of Justice (Department) is availing itself of this authority to allow a NACARA applicant to submit, as evidence of commencement of physical presence in the United States, other documentation issued by state and local authorities (such as school, hospital, police, and public assistance records). The Department believes that these evidentiary options may well provide sufficient opportunities for qualified applicants to establish commencement of physical presence in the United States without encouraging fraudulent applications. However, in order to ensure that no significant group of eligible aliens is precluded from establishing eligibility for NACARA benefits, the Department is soliciting public comments on the need for any additional methods of establishing commencement of physical presence in the United States and suggestions as to what those additional methods should be, including whether the documentary standards listed in 8 CFR 245.13(e)(3) for demonstrating continuity of physical presence should also be applied to the requirement for demonstrating commencement of physical presence. Commenters are encouraged to explain which classes of aliens would benefit from the proposal, and how the proposal could be implemented without severely compromising the integrity of the adjudicative process.

The NACARA statute is silent as to the methods by which an applicant may demonstrate the continuity of his or her physical presence in the United States. By regulation, the Department is hereby providing that a NACARA applicant may demonstrate continuity of physical presence in the United States through the submission of one or more documents issued by any governmental or non-governmental authority. Such documentation must bear the name of the applicant, have been dated at the time it was issued, and bear the signature of the issuing authority. In some cases, a single document may suffice to establish continuity for the entire post-December 1, 1995, period, while in other cases the alien may need to submit a number of documents. For example, a college transcript or an employment record may show that an applicant attended school or worked in the United States throughout the entire post-December 1, 1995, period. On the other hand, an applicant would need to submit a number of monthly rent receipts or electric bills to establish the same continuity of presence. While the Department neither requires nor wants the applicant to submit documentation to show presence on every single day since December 1, 1995, there should be no significant chronological gaps in the documentation, either. Generally, a gap of 3 months or less in documentation is not considered significant. Furthermore, if the applicant is aware of documents already contained in this or her Immigration and Naturalization Service (Service) file that establish physical presence, he or she may merely list those documents, giving the type and date of the document. Examples of such documents might include a written copy of a sworn statement given to a Service officer, the transcript of a formal hearing, and a Record of Deportable/Inadmissible Alien (Form I–213).

How Does an Applicant Establish Admissibility?

The grounds of inadmissibility specified in paragraphs (4) (public charge), (5) (lack of labor certification), (6)(A) (illegal entry), (7)(A) (immigrant not in possession of an immigrant visa or other valid entry document), and (9)(B) (unlawful presence) of section 212(a) of the Act do not apply to NACARA applicants. Additionally, a Nicaraguan or Cuban national present in the United States who has been ordered excluded, deported, or removed from, or who has agreed to depart voluntarily from, the United States may apply for adjustment of status under NACARA.

If a NACARA applicant is inadmissible to the United States under one of the grounds of inadmissibility contained in section 212(a) of the Act other than those specifically excepted by NACARA, but is eligible for an individual waiver of that ground of inadmissibility, he or she may file an application for the waiver concurrently with his or her application for adjustment of status. Adjustment of status may not be granted unless the waiver has first been approved.

How Do the Provisions of NACARA Affect Dependents of Nicaraguan and Cuban Nationals?

The provisions of NACARA also apply to certain dependents. To receive NACARA benefits as a dependent of a NACARA beneficiary, an alien would have to be a national of either Nicaragua or Cuba (but need not necessarily be of the same nationality as the principal beneficiary—a Cuban dependent could qualify through a Nicaraguan principal beneficiary and vice versa); would have to be the spouse, child (i.e., under 21 years of age and unmarried), or unmarried son or daughter (i.e., 21 years of age or older) of a NACARA principal beneficiary at the time of the principal beneficiary's adjustment of status to that of permanent resident; and would have to be admissible to the United States under section 212(a) of the Act (other than those provisions specifically excepted by NACARA). NACARA dependents must be physically present in the United States in order to apply

and must properly file an application before April 1, 2000.

Additionaly, an unmarried son or daughter, other than a child as defined in section 101(b)(1) of the Act, would have to have been physically present in the United States continuously since December 1, 1995 (not counting absences totaling 180 days or fewer). Although many qualifying dependents of NACARA principal beneficiaries would be able to receive NACARA benefits in their own right, some would only be able to qualify under the dependent provisions. Examples of otherwise eligible persons who could only qualify as dependents would include a spouse or child who arrived in the United States between December 1, 1995, and the principal beneficiary's filing date, and a spouse or child who had been absent for an aggregate of more than 180 days.

How Are Dependents Who Do Not Meet NACARA Requirements Affected?

A family member who is unable to qualify for NACARA adjustment of status on his or her own, or as a dependent under the provisions of NACARA, may eventually become eligible for lawful permanent resident status under other provisions of the Act. Examples of such individuals would include a dependent who is not a national of Nicaragua or Cuba, a spouse or child whose relationship to the principal applicant is not established until after the principal applicant is granted permanent resident status, and an unmarried son or daughter over the age of 21 who entered the United States after December 1, 1995. Upon becoming a permanent resident, a NACARA beneficiary could file a visa petition to accord such a dependent immigrant classification under section 203(a)(2) of the Act, thereby enabling the dependent who is not eligible for NACARA benefits to seek immigration to the United States through the normal family-based immigration process.

What Happens if an Applicant Is Already in Exclusion, Deportation, or Removal Proceedings, or Has a Motion To Reopen or Motion To Reconsider Pending Before the Immigration Court or the Board of Immigration Appeals (Board)?

Proceedings Pending Before the Executive Office for Immigration Review (EOIR)

Persons who have proceedings pending before an Immigration Court or the Board, or persons who have a pending motion to reopen or reconsider filed on or before May 21, 1998, shall remain within the jurisdiction of EOIR for the purpose of consideration of applications for adjustment of status under section 202 of NACARA.

Proceedings Pending Before an Immigration Judge

If an alien (other than an arriving alien who has not been paroled into the United States) is in exclusion, deportation, or removal proceedings before an immigration judge, or if an alien has a motion to reopen or motion to reconsider filed on or before May 21, 1998 pending before an immigration judge, jurisdiction over an application for adjustment of status under section 202 of NACARA shall lie with the Immigration Court. The procedure for filing an application for adjustment under NACARA is described below. If an alien who is not clearly ineligible for adjustment of status under section 202 of NACARA and who has a pending motion to reopen or motion to reconsider files an application for adjustment of status under section 202 of NACARA, the immigration judge shall reopen the alien's proceedings for consideration of the adjustment application. Applications shall be subject to the filing requirements of 8 CFR 3.11 and 3.31.

Proceedings Pending Before the Board

If an alien who is not clearly ineligible for adjustment of status under section 202 of NACARA has a pending appeal with the Board, the Board shall remand the proceedings to the immigration judge for the sole purpose of adjudicating the application for adjustment. The Board shall so remand the case regardless of whether the alien has already filed an application for adjustment of status under NACARA. Further, if an alien has a pending motion to reopen or motion to reconsider filed with the Board on or before May 21, 1998, the Board shall reopen and remand the proceedings to the immigration judge for the sole purpose of adjudicating an application for adjustment of status under section 202 of NACARA.

If upon remand the immigration judge denies the application, or the alien fails to file an application for adjustment under section 202 of NACARA, the immigration judge shall return the case to the Board by certification. This will allow the Board to consider the denial of the NACARA application as well as all other outstanding issues from the previously pending appeal or motion. The alien shall not be required to file another Notice of Appeal to the Board of Immigration Appeals of Decision of Immigration Judge (Form EOIR–26), or to pay an appeal filing fee because the immigration judge's certification of the denial to the Board will automatically transfer the immigration judge's decision to the Board.

May an Alien Who Is in Proceedings Before an Immigration Court or the Board of Immigration Appeals Apply for Adjustment of Status Before the Service?

Yes, under certain circumstances. An alien who is in exclusion, deportation, or removal proceedings before an Immigration Court or the Board may move to have the proceeding administratively closed for the purpose of filing an application for adjustment under NACARA. If the Service concurs in such motion, the Immigration Court or the Board, as appropriate, will administratively close the proceedings. Such closure would permit recalendaring of the closed proceedings if, for example, the alien fails to file an application for adjustment of status under NACARA before April 1, 2000, or the Service denies any application for adjustment of status filed by the alien under NACARA. Should the Service deny the application of status filed by the alien under NACARA. Should the Service deny the application, or the alien fail to file the application before April 1, 2000, the Service will move to recalendar the proceedings and the proceedings will be recalendared by the Immigration Court or the Board, as appropriate. In the case of an application denied by the Service, the alien could seek reconsideration of the denied adjustment application in such recalendared proceedings.

What Happens if an Applicant Is the Subject of a Final Order of Removal?

An alien who is the subject of a final order of removal, and who has never filed an application for adjustment of status under section 202 of NACARA with the Immigration Court, must file such application with the Service. However, if such alien has a motion to reopen or a motion to reconsider filed on or before May 2, 1998 pending before an Immigration Court or the Board, then the application for adjustment must be filed with the Immigration Court or with the Board, as appropriate. The mere filing of an application for adjustment of status under section 202 of NACARA with the Service or the referral of a denied application to an immigration judge does not stay the execution of the final order of removal. To request that execution of the final order be stayed by the Service, the alien must file an Application for Stay of Removal (Form I–246), following the procedures set

forth in 8 CFR 241.6. If the application is referred to the immigration judge, and the Service does not grant a stay of execution of the final order, the alien must request that the immigration judge or Board specifically grant a stay of execution of the final order of removal pursuant to 8 CFR 245.13(d)(5)(ii).

When Can an Application Be Filed?

The application period for NACARA benefits begins June 22, 1998 and ends on March 31, 2000.

What Forms and Other Documents Should Be Filed?

Each applicant for NACARA adjustment of status benefits must file a separate Application to Register Permanent Residence or Adjust Status (Form I–485), accompanied by the required application fee and supporting documents described below. NACARA applicants should complete Part 2 (Application Type) of that form by checking box ''h—other'' and writing ''NACARA—Principal'' or ''NACARA—Dependent'' next to that block. Each application filed must be accompanied by the required initial evidence: (1) a birth certificate or other record of birth; (2) two photographs as described in the Form I–485 instructions; (3) a completed Biographic Information Sheet (Form G–325A) if the applicant is between 14 and 79 years of age; (4) a report of medical examination; (5) if the applicant is at least 14 years of age, a local police clearance from each jurisdiction where the alien has resided for six months or longer since arriving in the United States; (6) a copy of the applicant's Arrival-Departure Record (Form I–94) or other evidence of inspection and admission or parole into the United States, if applicable; (7) one or more of the documents described in section 202(b)(2) of NACARA and 8 CFR 245.13(e)(2) to establish commencement of physical presence in the United States; and (8) one or more of the documents described in 8 CFR 245.13(e)(3) to establish continuity of physical presence in the United States. In addition, the applicant must submit a statement showing all departures from and arrivals in the United States since December 1, 1995. Finally, if the alien is applying as the spouse, child, or unmarried son or daughter of another NACARA beneficiary, the applicant must submit evidence of the relationship (for example, a marriage certificate).

Must the Applicant Be Fingerprinted?

Yes. Upon receipt of the application, the Service will instruct the applicant regarding procedures for obtaining fingerprints through one of the Service's Application Support Centers (ASCs) or authorized Designated Law Enforcement Agencies (DLEAs) chosen specifically for that purpose. Those instructions will direct the applicant to the ASC or DLEA nearest the applicant's home, and advice the applicant of the date(s) and time(s) fingerprinting services may be obtained. Applicants should not submit fingerprint cards as part of the initial filing.

Is There a Fee for Filing This Application?

NACARA adjustment of status applications must be submitted with the fee required by 8 CFR 103.7(b)(1) for Form I–485 (currently $130 for applicants 14 years of age or older, and $100 for applicants under age 14). If the application is submitted to the INS Texas Service Center, the fee must also be submitted to that center. If the application is submitted to an Immigration Court or the Board of Immigration Appeals, the fee must be submitted to the appropriate local office of the Service in accordance with 8 CFR 3.31. An applicant who is deserving of the benefits of section 202 of NACARA and is unable to pay the filing fee may request a fee waiver in accordance with 8 CFR 103.7(c).

How and Where Should the Application Be Filed?

If the applicant is not in exclusion, deportation, or removal proceedings before an Immigration Court or the Board of Immigration Appeals, the application and attachments must be submitted by mail to: USINS Texas Service Center, P.O. Box 851804, Mesquite, TX 75185–1804. If the applicant is in proceedings pending before an Immigration Court or the Board of Immigration Appeals, or if the applicant has a motion to reopen or motion to reconsider filed on or before May 21, 1998 pending before an Immigration Court or the Board, the application and attachments must be submitted to the Immigration Court with jurisdiction over the case or to the Board if the Board has jurisdiction. In such cases, the fee should be submitted to the Service pursuant to 8 CFR 3.31, as provided above. It should be noted that if the motion to reopen or motion to reconsider is filed after May 21, 1998, jurisdiction over any application for adjustment of status under NACARA lies with the Service, not with EOIR.

Applications for adjustment of status under NACARA may not be submitted to any other Service locations or to any consular posts.

Will an Applicant Filing an Application for Adjustment of Status Under NACARA With the Service Be Required to Appear Before the Service for an Interview?

The decision whether to require an interview is solely within the discretion of the Service. The Service may elect to waive the interview of the applicant. If the application is adjudicated without interview, a notice of the decision will be mailed to the applicant. If an interview is required, the application will be forwarded to the local Service office having jurisdiction over the applicant's place of residence. The applicant will be notified of the date and time to appear for the interview. If an applicant fails to appear for an interview, the application may be denied in accordance with existing regulations.

Can an Applicant Be Authorized To Work While the Application Is Pending?

An unexpired authorization to accept employment under another provision of the Act will not be invalidated by the filing of an application for adjustment of status under NACARA or by the administrative closure of the exclusion, deportation, or removal proceeding to pursue relief pursuant to NACARA. Furthermore, an applicant for adjustment under NACARA is not precluded from applying for, and being granted, an extension of any such employment authorization for which he or she remains eligible. Any applicant for adjustment of status under NACARA who wishes to obtain initial employment authorization, or continued employment authorization when his or her prior authorization expires, during the pendency of the adjustment of status application may file an Application for Employment Authorization (Form I–765), in accordance with the instructions on the form. With limited exceptions, the interim rule provides that employment authorization will not be granted until the application for adjustment has been pending for 180 days. This approach is in keeping with section 202(c)(3) of NACARA, which mandates approval of employment authorization if the adjustment application ''is pending for a period exceeding 180 days,'' and has not been denied, and which authorizes, but does not mandate, approval of employment authorization if the application has been pending for fewer than 180 days. Under the interim rule, the Department will authorize employment for applicants whose cases have been pending for fewer than 180 days only if the

applicant applies for work authorization and adjustment at the same time. In addition, the Service record must contain evidence that the applicant is a national of Nicaragua or Cuba who had applied to the Service for an immigration benefit, or had been placed in deportation or exclusion proceedings, not later than December 1, 1995, as provided in paragraphs (1)(A)(i) through (v) and (vii) of section 202(b) of NACARA, unless the record also shows that the applicant is clearly ineligible for adjustment of status under NACARA (e.g., the applicant has been convicted of an aggravated felony). The potential benefits of filing for adjustment of status and employment authorization concurrently will be emphasized during public information sessions that the Service will hold with local community groups. The Department believes that limited employment authorization to these circumstances and to circumstances in which 180 days have elapsed since the filing of the application will both: (1) discourage fraudulent applications filed simply as a way to gain work authorization, and (2) permit employment more promptly for those whose applications appear likely to be granted. However, in publishing this interim rule the Department solicits the views of interested parties on this topic.

Can an Application for Adjustment of Status Be Submitted if the Alien Is Outside the United States?

No. The statute and regulations require that an alien be physically present in the United States in order to properly file an application. However, the regulation does contain a special provision allowing an otherwise eligible alien who is outside the United States to submit a request for parole authorization. Such request would have to be accompanied by photocopies of the documents the alien intends to file in support of his or her claim for eligibility for adjustment of status under NACARA if the parole authorization is granted. Parole authorization may be granted, as a matter of discretion, if upon review of the application for parole authorization and related documents it is determined that the application for adjustment of status is likely to be approved once it has been properly filed. The alien would be allowed to file the application after being paroled into the country. Accordingly, the alien must remain outside the United States until the request for parole authorization is approved. Any attempt to enter the United States without the parole authorization could result in the alien's being found inadmissible to, and removed from, the United States.

Can an Applicant Travel Outside the United States While the Application Is Pending?

Nothing in NACARA authorizes the Service to allow an applicant to re-enter the United States without proper documents. If an applicant plans to leave the United States to go to any other country, including Canada or Mexico, before a decision is made on his or her NACARA adjustment application, the applicant should contact the Service to request advance authorization for parole. If an applicant leaves the United States without such advance authorization, action on his or her NACARA adjustment application may be terminated and the application may be denied. An applicant may also experience difficulty when returning to the United States if he or she does not have such advance authorization. Furthermore, any absence from the United States without an advance parole authorization issued prior to departure counts toward the 180-day aggregate time period that the applicant is allowed to be outside the United States.

If an Alien Who Is Under a Final Order of Exclusion, Deportation, or Removal Departs From the United States, Will the Alien Be Effecting His or Her own Exclusion, Deportation, or Removal?

Yes. Such alien would be a ''self-deport'' and would be subject to the inadmissibility provisions of section 212(a)(9) of the Act, regardless of whether the alien obtained an Authorization for Parole of an Alien Into the United States (Form I–512) prior to departure. While being inadmissible would not preclude the alien from being *paroled* into the United States, it would preclude the alien from being *admitted* to the United States or being granted an adjustment of status, unless the alien first applied for and was granted permission to reapply for admission into the United States.

How Can an Alien Apply for Such Permission?

An Alien needing such permission may file an Application for Permission to Reapply for Admission Into the United States After Deportation or Removal (Form I–212), in accordance with the instructions on that form. Form I–212 may be filed prior to the alien's departure.

Can an Alien Who Has Not Filed the Application for Adjustment Obtain a Form I–512?

Once this regulation becomes effective on June 22, 1998, and except as discussed above, only the NACARA-eligible aliens who have filed an application for adjustment of status will be able to obtain a Form I–512. However, because some individuals may need to travel prior to that date, on December 24, 1997, the Service issued instructions to all local Service offices allowing district directors to issue Form I–512 to aliens who appear to be eligible for adjustment of status under NACARA and need to travel. The interim rules provides that for aliens who departed the United States with a Form I–512 issued pursuant to those December 24, 1997, instructions, the 180-day cumulative period during which an alien may be absent without breaking continuous physical presence in the United States in tolled while the alien is outside the United States in accordance with the conditions of the advance parole authorization. In this fashion, the Department precludes undue hardships for the affected individuals.

Furthermore, for those aliens who were not issued a Form I–512 because they departed before the Service could implement the December 24, 1997, instructions, the interim rule provides for the tolling of the 180-day cumulative period from November 19, 1997, until July 20, 1998, provided the alien departed from the United States prior to December 31, 1997. This provision extends until July 20, 1998, in order to provide interested aliens 30 days from the effective date of the interim regulation to file the application for parole authorization with the Texas Service Center. As discussed above, once the application for parole authorization has been filed the 180-day cumulative period during which an alien is not required to be physically present in the United States is tolled, provided the application for parole authorization is granted. Such tolling would remain in effect until the alien arrives in the United States with the Form I–512 issued by the director of the Texas Service Center.

What Documentation Will Be Issued if the Adjustment Application Is Approved?

After processing is completed, a notice of the decision will be mailed to the NACARA applicant. Applicants should keep this notice for their records. If the application has been approved, an alien registration receipt card will be

mailed separately to the applicant. To obtain temporary evidence of lawful permanent resident status, the applicant may present the original approval notice and his or her passport or other photo identification at his or her local Service office. The local Service office will issue temporary evidence of lawful permanent resident status after verifying the approval of the NACARA adjustment of status application. If the applicant is not in possession of a passport in which such temporary evidence may be endorsed, he or she should also submit two photographs meeting Alien Documentation, Identification, and Telecommunication System (ADIT) specifications so that the Service may prepare and issue temporary evidence of lawful permanent residence status. If the alien previously had been issued a final order of exclusion, deportation, or removal, such order shall be deemed canceled as of the date of the approval of the application for adjustment of status. If the alien had been in exclusion, deportation, or removal proceedings that were administratively closed, such proceedings shall be deemed terminated as of the date of approval of the application for adjustment of status .

What Happens if an Application Is Denied by the Service?

If the Service finds that an applicant is ineligible for adjustment of status under NACARA, the Service will advise him or her of its determination and of the applicant's right to seek, and the procedures for seeking, consideration of the application by an immigration judge. Depending on the individual case circumstances, those procedures could take one of three different routes as follows:

(1) If exclusion, deportation, or removal proceedings had never been commenced, the Service will issue a Notice to Appear, thereby initiating removal proceedings during which the applicant may renew his or her application for adjustment under NACARA before an Immigration Court. In such proceedings, the immigration judge shall adjudicate the renewed application.

(2) If exclusion, deportation, or removal proceedings had been initiated and administratively closed under the procedure set forth in 8 CFR 245.13(d)(3), the Service will advise the alien of the Service's denial of the NACARA adjustment application and will move the Immigration Court, or the Board if at the time of administrative closure the Board had jurisdiction over the case, to recalendar the proceeding. The previously closed removal proceedings will then be recalendared by the Immigration Court or the Board, as appropriate.

(3) If a final order of exclusion, deportation, or removal had been issued, the Service, using Form I–290C, Notice of Certification, will refer its decision to deny the NACARA adjustment application to an immigration judge, who will adjudicate the application in proceedings designed solely for the purpose of such adjudication.

What Happens if an Application Is Denied by the Immigration Court?

If the Immigrant Court denies the NACARA adjustment application of an alien in exclusion, deporting, or removing proceedings before the Immigration Court, the decision to appealed to the Board along with and under the same procedures as all other issues before the Immigration Court in those proceedings. If the Immigration Court denies the NACARA adjustment application of an alien whose case was remanded to the Immigration Court by the Board, the Immigration Court shall certify the decision to the Board for review. If the Immigration Court denies the NACARA adjustment application of an alien whose case was referred by the Service for a NACARA-only inquiry, the alien shall have the right to appeal the decision of the Board, subject to the requests for 8 CFR parts 3 and 240 governing appeals from immigration judges to the Board, including the requirements of filing a Notice of Appeal to the Board of Immigration Appeals of Decision of Immigration Judge (Form EOIR–26) and paying the filing fee.

What Happens if an Alien Fails To Appear for a Hearing Before the Immigration Judge on a NACARA Adjustment as Applicable?

An alien must appear for all scheduled hearings before an immigration judge, unless his or her appearance is waived by the immigration judge. An alien who is in exclusion, deportation, or removal proceedings before the immigration judge and who fails to appear for a hearing regarding a NACARA adjustment application will be subject to the applicable statutory and regulatory *in absentia* procedures (i.e., section 242B of the Act as it existed prior to the amendments of the Illegal Immigration Reform and Immigrant Responsibility Act of 1996 (IIRIRA) on September 30, 1996, for deportation proceedings, and section 240 of the Act as amended IIRIRA for removal proceedings).

What Rules of Procedure Apply in NACARA-only Hearings Conducted on Cases Referred by the Service to the Immigration Court?

Although an alien who is placed before the immigration judge for a NACARA-only hearing after referral on a Notice of Certification (Form I–290) to the Immigration Court by the Service is not specifically subject to the statutory and regulatory provisions governing exclusion, deportation, and removal proceedings, the Department has inserted language in this interim rule reflecting the standards in section 240 of the Act for removal proceedings, including the *in absentia* procedures. Absent specific statutory direction in this area, the procedures of section 240 of the Act were chosen because such procedures are similar to those from the pre-IIRIRA section 242B of the Act and indicate Congress's most recent preference for procedures dealing with failures to appear for immigration proceedings. Use of the language from section 240 of the Act also assures that the *in absentia* procedures used for those in NACARA-only proceedings are consistent with the *in absentia* procedures applicable to aliens who file NACARA adjustment applications in ongoing removal and deportation proceedings.

As for those aliens who, upon reopening and remanding by the Board to the Immigration Court, fail to file a NACARA adjustment application with the Immigration Court, the immigration judge will certify the case back to the Board for consideration of the previously pending appeal or motion. If, prior to receiving a final order from the Board, the alien subsequently requests as remand to file a NACARA adjustment application, the Board shall remand the case to the Immigration Court, unless the alien is clearly ineligible for such relief.

Good Cause Exception

The Department's implementation of this rule as an interim rule, with provision for post-promulgation public comment, is based upon the ''good cause'' exceptions found at 5 U.S.C. 553(b)(B). Section 202 of NACARA became effective immediately upon enactment on November 19, 1997. Publication of this rule as an interim rule will expedite implementation of that section and allow Nicaraguan and Cuban nationals and their spouses and children to apply for and obtain the benefits available to applicants for adjustment of status under NACARA as soon as possible before the statutory application deadline of April 1, 2000.

Regulatory Flexibility Act

In accordance with 5 U.S.C. 605(b), the Attorney General certifies that this rule will not, if promulgated, have a significant adverse economic impact on a substantial number of small entities. This rule allows certain Nicaraguan and Cuban nationals to apply for adjustment of status; it has no effect on small entities as that term is defined in 5 U.S.C. 601(6).

Executive Order 12866

This rule is considered by the Department of Justice 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.

Executive Order 12612

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

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 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.

Executive Order 12988

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

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

Paperwork Reduction Act

The information collection requirements contained in this rule have been approved for use by the Office of Management and Budget (OMB) under the Paperwork Reduction Act. The OMB control number for this collection is contained in 8 CFR 299.5, Display of control numbers.

List of Subjects

8 CFR Part 3

Administrative practice and procedure, Immigration, Organization and functions (Government agencies).

8 CFR Part 240

Administrative practice and procedure, Aliens, Immigration.

8 CFR Part 245

Alien, Immigration, Reporting and recordkeeping requirements.

8 CFR Part 274a

Administrative practice and procedure, Aliens, Employment, Penalties, Reporting and recordkeeping requirements.

8 CFR Part 299

Immigration, Reporting and recordkeeping requirements.

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

PART 3—EXECUTIVE OFFICE FOR IMMIGRATION REVIEW

1. The authority citation for part 3 continues to read as follows:

Authority: 5 U.S.C. 301; 8 U.S.C. 1103, 1252 note, 1252b, 1324b, 1362, 28 U.S.C. 509, 510, 1746; sec. 2, Reorg. Plan No. 2 of 1950; 3 CFR, 1949–1953 Comp., p. 1002.

2. Section 3.1 is amended by adding paragraph (b)(12) to read as follows:

§ 3.1 General authorities.

* * * * *

(b) * * *

(12) Decisions of Immigration Judges on applications for adjustment of status referred on a Notice of Certification (Form I–290C) to the Immigration Judge in accordance with § 245.13(n)(2) of this chapter or remanded to the Immigration Court in accordance with § 245.13(d)(2) of this chapter.

* * * * *

PART 240—PROCEEDINGS TO DETERMINE REMOVABILITY OF ALIENS IN THE UNITED STATES

3. The authority citation for part 240 is revised to read as follows:

Authority: 8 U.S.C. 1103, 1182, 1186a, 1224, 1225, 1226, 1227, 1251, 1252 note, 1252a, 1252b, 1362; sec. 202, Pub. L. 105–100 (111 Stat. 2160, 2193); 8 CFR part 2.

§ 240.1 [Amended]

4. In § 240.1, paragraph (a) is amended in the first sentence by adding the phrase ''and section 202 of Pub. L. 105–100'' immediately after the phrase ''and 249 of the Act''.

§ 240.11 [Amended]

5. In § 240.11, paragraph (a)(1) is amended in the first sentence by revising the phrase ''adjustment of status under section 1 of the Act of November 2, 1966 (as modified by section 606 of Pub. L. 104–132) or under section 101 or 104 of the Act of October 28, 1977,'' to read ''adjustment of status under section 1 of the Act of November 2, 1966 (as modified by section 606 of Pub. L. 104–208), section 101 or 104 of the Act of October 28, 1977, or section 202 of Pub. L. 105–100,''.

§ 240.31 [Amended]

6. Section 240.31 is amended in the first sentence by adding the phrase '', including the adjudication of applications for adjustment of status pursuant to section 202 of Pub. L. 105–100'' immediately after the phrase ''and this chapter''.

§ 240.41 [Amended]

7. In § 240.41, paragraph (a) is amended in the first sentence by adding the phrase ''and section 202 of Pub. L. 100'' after ''and 249 of the Act''.

PART 245—ADJUSTMENT OF STATUS TO THAT OF PERSON ADMITTED FOR PERMANENT RESIDENCE

8. The authority citation for part 245 is revised to read as follows:

Authority: 8 U.S.C. 1101, 1103, 1182, 1255; sec. 202, Pub. L. 105–100 (111 Stat. 2160, 2193); 8 CFR part 2.

9. Section 245.13 is added to read as follows:

§ 245.13 Adjustment of Status of Certain Nationals of Nicaragua and Cuba under Public Law 105–100.

(a) *Aliens eligible to apply for adjustment.* An alien is eligible to apply for adjustment of status under the provisions of section 202 of Pub. L. 105–100, if the alien:

(1) Is a national of Nicaragua or Cuba;

(2) Except as provided in paragraph (o) of this section, has been physically present in the United States for a continuous period beginning not later than December 1, 1995, and ending not earlier that the date the application for adjustment is granted, excluding:

(i) Any periods of absence from the United States not exceeding 180 days in the aggregate; and

(ii) Any periods of absence for which the applicant received an Advance Authorization for Parole (Form I–512) prior to his or her departure from the United States, provided the applicant returned to the United States in accordance with the conditions of such Advance Authorization for Parole;

(3) Is not inadmissible to the United States for permanent residence under any provisions of section 212(a) of the Act, with the exception of paragraphs (4), (5), (6)(A), (7)(A) and (9)(B). If available, an applicant may apply for an individual waiver as provided in paragraph (c) of this section;

(4) Is physically present in the United States at the time the application is filed; and

(5) Properly files an application for adjustment of status in accordance with this section.

(b) *Qualified family members.* (1) *Existence of relationship at time of adjustment.* The spouse, child, or unmarried son or daughter of an alien eligible for adjustment of status under the provisions of Pub. L. 105–100 is eligible to apply for benefits as a dependent provided the qualifying relationship existed when the principal beneficiary was granted adjustment of status and the dependent meets all applicable requirements of sections 202(a) and (d) of Pub. L. 105–100.

(2) *Spouse and minor children.* If physically present in the United States, the spouse or minor child of an alien who is eligible for permanent residence under the provisions of Pub. L. 105–100 may also apply for and receive adjustment of status under this section, provided such spouse or child meets the criteria established in paragraph (a) of this section, except for the requirement of continuous physical presence in the United States since December 1, 1995. Such application may be filed concurrently with or subsequent to the filing of the principal's application but may not be approved prior to approval of the principal's application.

(3) *Unmarried adult sons and daughters.* An unmarried son or daughter of an alien who is eligible for permanent residence under the provisions of Pub. L. 105–100 may apply for and receive adjustment under this section, provided such son or daughter meets the criteria established in paragraph (a) of this section.

(c) *Applicability of inadmissibility grounds contained in section 212(a).* An applicant for the benefits of the adjustment of status provisions of section 202 of Pub. L. 105–100 need not establish admissibility under paragraphs (4), (5), (6)(A), (7)(A), and (9)(B) of section 212(a) of the Act in order to be able to adjust his or her status to that of permanent resident. An applicant under section 202 of Pub. L. 105–100 may also apply for one or more of the immigrant waivers of inadmissibility under section 212 of the Act, if applicable, in accordance with § 212.7 of this chapter.

(d) *Aliens in exclusion, deportation, or removal proceedings, and aliens subject to a final order of exclusion, deportation, or removal.* (1) *Proceedings pending before an Immigration Court.* Except as provided in paragraph (d)(3) of this section, while an alien is in exclusion, deportation, or removal proceedings pending before an immigration judge, or has a pending motion to reopen or motion to reconsider filed with an immigration judge on or before May 21, 1998, sole jurisdiction over an application for adjustment of status under section 202 of Public Law 105–100 shall lie with the immigration judge. If an alien who has a pending motion to reopen or motion to reconsider filed with an immigration judge on or before May 21, 1998 files an application for adjustment of status under section 202 of Pub. L. 105–100, the immigration judge shall reopen the alien's proceedings for consideration of the adjustment application, unless the alien is clearly ineligible for adjustment of status under section 202 of Pub. L. 105–100. All applications for adjustment of status under section 202 of Pub. L. 105–100 filed with an Immigration Court shall be subject to the requirements of §§ 3.11 and 3.31 of this chapter.

(2) *Proceedings pending before the Board of Immigration Appeals.* Except as provided in paragraph (d)(3) of this section, in the case of an alien who either has a pending appeal with the Board or has a pending motion to reopen or motion to reconsider filed with the Board on or before May 21, 1998, the Board shall remand, or reopen and remand, the proceedings to the Immigration Court for the sole purpose of adjudicating an application for adjustment of status under section 202 of Pub. L. 105–100, unless the alien is clearly ineligible for adjustment of status under section 202 of Pub. L. 105–100. If the immigration judge denies, or the alien fails to file, the application for adjustment of status under section 202 of Pub. L. 105–100, the immigration judge shall certify the decision to the Board for consideration in conjunction with the applicant's previously pending appeal or motion.

(3) *Administrative closure of pending exclusion, deportation, or removal proceedings.* (i) In the case of an alien who is in exclusion, deportation, or removal proceedings, or has a pending motion to reopen or a motion to reconsider such proceedings filed on or before May 21, 1998, and who appears to be eligible to file an application for adjustment of status under section 202 of Pub. L. 105–100, the Immigration Court having jurisdiction over such proceedings or motion, or if the matter is before the Board on appeal or by motion, the Board, shall, upon request of the alien and with the concurrence of the Service, administratively close the proceedings, or continue indefinitely the motion, to allow the alien to file such application with the Service as prescribed in paragraph (g) of this section.

(ii) In any case not administratively closed in accordance with paragraph (d)(3)(i) of this section, the immigration judge having jurisdiction over the exclusion, deportation, or removal proceedings shall have jurisdiction to accept and adjudicate any application for adjustment of status under section 202 of Pub. L. 105–100 during the course of such proceedings.

(4) *Aliens with final orders of exclusion, deportation, or removal.* An alien who is subject to a final order of exclusion, deportation, or removal, and who has not been denied adjustment of status under section 202 of Public Law 105–100 by the immigration judge or the Board of Immigration Appeals, may apply to the Service for adjustment of status under section 202 of Pub. L. 105–100.

(5) *Stay of final order of exclusion, deportation, or removal.* (i) *With the Service.* The filing of an application for adjustment under section 202 of Public Law 105–100 with the Service shall not stay the execution of such final order unless the applicant has filed, and the Service has approved an Application for Stay of Removal (Form I–246) in accordance with section 241(c)(2) of the Act and § 241.6 of this chapter.

(ii) *With EOIR.* When the Service refers a decision to an immigration judge on a Notice of Certification (Form I–290C) in accordance with paragraph (m)(3) of this section, the referral shall not stay the execution of the final order. Execution of such final order shall proceed unless a stay of execution is specifically granted by the immigration judge, the Board, or an authorized Service officer.

(6) *Effect on applications for adjustment under other provisions of the law.* Nothing in this section shall be deemed to allow any alien who is in either exclusion proceedings that commenced prior to April 1, 1997, or

removal proceedings as an inadmissible arriving alien that commenced on or after April 1, 1997, and who has not been paroled into the United States, to apply for adjustment of status under any provision of law other than section 202 of Pub. L. 105–100.

(e) *Application and supporting documents.* Each applicant for adjustment of status must file an Application to Register Permanent Residence or Adjust Status (Form I–485). An applicant should complete Part 2 of Form I–485 by checking box ''h—other'' and writing ''NACARA—Principal'' or ''NACARA—Dependent'' next to that block. Each application must be accompanied by:

(1) The fee prescribed in § 103.7(b)(1) of this chapter;

(2) Evidence of commencement of physical presence in the United States not later than December 1, 1997. Such evidence may consist of either:

(i) Documentation evidencing one or more of the activities specified in section 202(b)(2)(A) of Pub. L. 105–100, or

(ii) Other documentation issued by a Federal, State, or local authority provided such other documentation bears the seal of such authority, was dated at the time of issuance, and bears a date of issuance not later than December 1, 1995. Examples of such other documentation include, but are not limited to:

(A) A State driver's license;

(B) A State identification card issued in lieu of a driver's license to a non-driver;

(C) A county or municipal hospital record;

(D) A public college or public school transcript; and

(E) Income tax records;

(3) Evidence of continuity of physical presence in the United States issued by any governmental or non-governmental authority, provided such evidence bears the name of the applicant, was dated at the time it was issued, and bears the signature of the authorized representative of the issuing authority. There should be no chronological gaps in such documentation exceeding 90 days in length, excluding periods when the applicant states that he or she was not physically present in the United States. Such documentation need not bear the seal of the issuing authority and may include, but is not limited to:

(i) School records;

(ii) Rental receipts;

(iii) Utility bill receipts;

(iv) Any other dated receipts;

(v) Personal checks written by the applicant bearing a dated bank cancellation stamp;

(vi) Employment records, including pay checks;

(vii) Credit card statements showing the dates of purchase, payment, or other transaction; and

(viii) For applicants who have had ongoing correspondence or other interaction with the Service, a list of the types and dates of such correspondence or other contact that the applicant knows to be contained or reflected in Service records;

(4) A copy of the applicant's birth certificate;

(5) A complete Biographic Information Sheet (Form G–325A), if the applicant is between 14 and 79 years of age;

(6) A report of medical examination, as specified in § 245.5 of this chapter;

(7) Two photographs, as described in the instructions to Form I–485;

(8) If the applicant is 14 years of age or older, a police clearance from each municipality where the alien has resided for six months or longer since arriving in the United States;

(9) If the applicant is applying as the spouse of another Pub. L. 105–100 beneficiary, a copy of their certificate of marriage and copies of documents showing the legal termination of all other marriages by the applicant or the other beneficiary;

(10) If the applicant is applying as the child, unmarried son, or unmarried daughter of another (principal) beneficiary under section 202 of Pub. L. 105–100 who is not the applicant's biological mother, copies of evidence (such as the applicant's parent's marriage certificate and documents showing the legal termination of all other marriages, an adoption decree, or other relevant evidence) to demonstrate the relationship between the applicant and the other beneficiary;

(11) A copy of the Arrival-Departure Record (Form –I–94) issued at the time of the applicant's arrival in the United States, if the alien was inspected and admitted or paroled; and

(12) If the applicant has departed from and returned to the Untied States since December 1, 1995, an attachment on a plain piece of paper showing:

(i) The date of the applicant's last arrival in the United States before or on December 1, 1995;

(ii) The date of each departure (if any) from the United States since that arrival;

(iii) The reason for each departure; and

(iv) The date, manner, and place of each return to the United States.

(f) *Secondary evidence.* If the primary evidence required in paragraph (e)(4), (e)(9) or (e)(10 of this section is unavailable, church or school records, or other secondary evidence pertinent to the facts in issue, may be submitted. If such documents are unavailable, affidavits may be submitted. The applicant may submit as many types of secondary evidence as necessary to establish the birth, marriage, or other event. Documentary evidence establishing that primary evidence is unavailable must accompany secondary evidence of birth or marriage in the home country. In adjudicating the application for adjustment of status under section 202 of Public Law 105–100, the Service or immigration judge shall determine the weight to be given such secondary evidence. Secondary evidence may not be submitted in lieu of the documentation specified in paragraphs (e)(2) and (e)(3) of this section. However, subject to verification by the Service, if the documentation specified in paragraphs (e)(2) and (e)(3) is already contained in the Service's file relating to the applicant, the applicant may submit an affidavit to that effect in lieu of the actual documentation.

(g) *Filing.* The application period begins on June 22, 1998. To benefit from the provisions of section 202 of Public Law 105–100, an alien must properly file an application for adjustment of status before April 1, 2000. Except as provided in paragraph (d) of this section, all applications for the benefits of section 202 of Pub. L. 105–100 must be submitted by mail to: USINS Texas Service Center, P.O. Box 851804, Mesquite, TX 75185–1804. After proper filing of the application, the Service will notify the applicant to appear for fingerprinting as prescribed in § 103.2(e) of this chapter.

(h) *Jurisdiction.* Except as provide din paragraphs (d) and (i) of this section, the director of the Texas Service Center shall have jurisdiction over all applications for adjustment of status under section 202 of Public Law 105–100.

(i) *Interview.* (1) Except as provided in paragraphs (d), (i)(2), and (i)(3) of this section, all applicants for adjustment of status under section 202 of Pub. L. 105–100 must be personally interviewed by an immigration officer at a local office of the Service. In any case in which the director of the Texas Service Center determines that an interview of the applicant is necessary, that director shall forward the case to the appropriate local Service office for interview and adjudication.

(2) In the case of an applicant who has submitted evidence of commencement of physical presence in the United States consisting of one or more of the documents specified in section 202(b)(2)(A)(i) through (v) or section

202(b)(2)(A)(vii) of Pub. L. 105–100 and upon examination of the application, including all other evidence submitted in support of the application, all relevant Service records and all other relevant law enforcement indices, if the director of the Texas Service Center determines that the alien is clearly eligible for adjustment of status under Pub. L. 105–100 and that an interview of the applicant is not necessary, the director may approve the application.

(3) Upon examination of the application, all supporting documentation, all relevant Service records, and all other relevant law enforcement indices, if the director of the Texas Service Center determines that the alien is clearly ineligible for adjustment of status under Pub. L. 105–100 and that an interview of the applicant is not necessary, the director may deny the application.

(j) *Authorization to be employed in the United States while the application is pending.* (1) *Application.* An applicant for adjustment of status under section 202 of Pub. L. 105–100 who wishes to obtain initial or continued employment authorization during the pendency of the adjustment application must file an Application for Employment authorization (Form I–765), with fee as set forth in § 103.7(b)(1) of this chapter. The applicant may either submit Form I–765 concurrently with Form I–485 or wait for at least 90 days after submission of Form I–485.

(2) *Adjudication and issuance.* In general, employment authorization may not be issued to an applicant for adjustment of status under section 202 of Pub. L. 105–100 until the adjustment application has been pending for 180 days. However, if Service records contain one or more of the documents specified in section 202(b)(2)(A)(i) through (v) and (vii) of Pub. L. 105–100, evidence of the applicant's Nicaraguan or Cuban nationality, and no indication that the applicant is clearly ineligible for adjustment of status under section 202 of Pub. L. 105–100, the application for employment authorization may be approved, and the resulting document issued immediately upon verification that the Service record contains such information. If the Service fails to adjudicate the application for employment authorization upon expiration of the 180-day waiting period or within 90 days of the filing of application for employment authorization, whichever comes later, the alien shall be eligible for interim employment authorization in accordance with § 274a.13(d) of this chapter. Nothing in this section shall preclude an applicant for adjustment of status under Pub. L. 105–100 from being granted an initial employment authorization or an extension of employment authorization under any other provision of law or regulation for which the alien may be eligible.

(k) *Parole authorization for purposes of travel.* (1) *Travel from and return to the United States while the application for adjustment of status is pending.* If an applicant for benefits under section 202 of Pub. L. 105–100 desires to travel outside, and return to, the United States while the application for adjustment of status is pending, he or she must file a request for advance parole authorization on an Application for Travel Document (Form I–131), with fee as set forth in § 103.7(b)(1) of this chapter and in accordance with the instructions on the form. If the alien is either in deportation or removal proceedings, or subject to a final order of deportation or removal, the Form I–131 must be submitted to the Assistant Commissioner for International Affairs; otherwise the Form I–131 must be submitted to the director of the Texas Service Center, who shall have jurisdiction over such applications. If any applicant departs the United States without first obtaining an advance parole, his or her application for adjustment of status under section 202 of Pub. L. 105–100 is deemed to be abandoned as of the moment of his or her departure.

(2) *Parole authorization for the purpose of filing an application for adjustment of status under section 202 of Pub. L. 105–100.* An otherwise eligible applicant who is outside the United States and wishes to come to the United States in order to apply for benefits under section 202 of Pub. L. 105–100 may request parole authorization for such purpose by filing an Application for Travel Document (Form I–131) with the Texas Service Center, at P.O. Box 851804, Mesquite, TX 75185–1804. Such application must be supported by a photocopy of the Form I–485 that the alien will file once he or she has been paroled into the United States. The applicant must include photocopies of all the supporting documentation listed in paragraph (e) of this section, except the filing fee, the medical report, the fingerprint card, and the local police clearances. If the director of the Texas Service Center is satisfied that the alien will be eligible for adjustment of status once the alien has been paroled into the United States and files the application, he or she may issue an Authorization for Parole of an Alien into the United States (Form I–512) to allow the alien to travel to, and be paroled into, the United States for a period of 60 days. The applicant shall have 60 days from the date of parole to file the application for adjustment of status. If the alien files the application for adjustment of status within that 60-day period, the Service may re-parole the alien for such time as is necessary for adjudication of the application. Failure to file such application for adjustment of status within 60 days shall result in the alien being returned to the custody of the Service and being examined as an arriving alien applying for admission. Such examination will be conducted in accordance with the provisions of section 235(b)(1) of the Act if the alien is inadmissible under section 212(a)(6)(C) or 212(a)(7) of the Act, or section 240 of the Act if the alien is inadmissible under any other grounds.

(3) *Effect of departure on an outstanding warrant of exclusion, deportation, or removal.* If an alien who is the subject of an outstanding final order of exclusion, deportation, or removal departs from the United States, with or without an advance parole authorization, such final order shall be executed by the alien's departure. The execution of such final order shall not preclude the applicant from filing an Application for Permission to Reapply for Admission Into the United States After Deportation or Removal (Form I–212) in accordance with § 212.2 of this chapter.

(l) *Approval.* If the director approves the application for adjustment of status under the provisions of section 202 of Pub. L. 105–100, the director shall record the alien's lawful admission for permanent resident as of the date of such approval and notify the applicant accordingly. If the alien had previously been issued a final order of exclusion, deportation, or removal, such order shall be deemed canceled as of the date of the director's approval of the application for adjustment of status. If the alien had been in exclusion, deportation, or removal proceedings that were administratively closed, such proceedings shall be deemed terminated as of the date of approval of the application for adjustment of status by the director. If an immigration judge grants or if the Board, upon appeal, grants an application for adjustment under the provisions of section 202 of Pub. L. 105–100, the alien's lawful admission for permanent residence shall be as of the date of such grant.

(m) *Denial and review of decision.* If the director denies the application for adjustment of status under the provisions of section 202 of Pub. L. 105–100, the director shall notify the

applicant of the decision. The director shall also:

(1) In the case of an alien who is not maintaining valid nonimmigrant status and who had not previously been placed in exclusion, deportation, or removal proceedings, initiate removal proceedings in accordance with § 239.1 of this chapter during which the alien may renew his or her application for adjustment of status under section 202 of Pub. L. 105–100; or

(2) In the case of an alien whose previously initiated exclusion, deportation, or removal proceeding had been administratively closed or continued indefinitely under paragraph (d)(3) of this section, advise the Immigration Court that had administratively closed the proceeding, or the Board, as appropriate, of the denial of the application. The Immigration Court or the Board will then recalendar or reinstate the prior exclusion, deportation, or removal proceeding, during which proceeding the alien may renew his or her application for adjustment under section 202 of Pub. L. 105–100; or

(3) In the case of an alien who is the subject of an outstanding final order of exclusion, deportation, or removal, refer the decision to deny the application by filing a Notice of Certification (Form I–290C) with the Immigration Court that issued the final order for consideration in accordance with paragraph (n) of this section.

(n) *Action of immigration judge upon referral of decision by a Notice of Certification (Form I–290C).* (1) *General.* Upon the referral by a Notice of Certification (Form I–290C) of a decision to deny the application, in accordance with paragraph (m)(3) of this section, and under the authority contained in § 3.10 of this chapter, the immigration judge shall conduct a hearing to determine whether the alien is eligible for adjustment of status under section 202 of Public Law 105–100. Such hearing shall be conducted under the same rules of procedure as proceedings conducted under part 240 of this chapter, except the scope of review shall be limited to a determination on the alien's eligibility for adjustment of status under section 202 of Public Law 105–100. During such proceedings all parties are prohibited from raising or considering any other issues, including but not limited to issues of admissibility, deportability, removability, and eligibility for any form of relief other than adjustment of status under section 202 of Public Law 105–100. Should the alien fail to appear for such hearing, the immigration judge shall deny the application for adjustment under section 202 of Public Law 105–100.

(2) *Appeal of immigration judge decision.* Once the immigration judge issues his or her decision on the application, either the alien or the Service may appeal the decision to the Board. Such appeal must be filed pursuant to the requirements for appeals to the Board from an immigration judge decision set forth in §§ 3.3 and 3.8 of this chapter.

(3) *Rescission of the decision of an immigration judge.* The decision of an immigration judge under paragraph (n)(1) of this section denying an application for adjustment under section 202 of Public Law 105–100 for failure to appear may be rescinded only:

(i) Upon a motion to reopen filed within 180 days after the date of the denial if the alien demonstrates that the failure to appear was because of exceptional circumstances as defined in section 240(e)(1) of the Act; or

(ii) Upon a motion to reopen filed at any time if the alien demonstrates that the alien did not receive notice of the hearing in person (or, if personal service was not practicable, through service by mail to the alien or to the alien's counsel of record, if any) or the alien demonstrates that the alien was in Federal or State custody and the failure to appear was through no fault of the alien.

(o) *Transition period provisions for tolling the physical presence in the United States provision for certain individuals.* (1) *Departure without advance authorization for parole.* In the case of an otherwise eligible applicant who departed the United States on or before December 31, 1997, the physical presence in the United States provision of section 202(b)(1) of Pub. L. 105–100 is tolled as of November 19, 1997, and until July 20, 1998.

(2) *Departure with advance authorization for parole.* In the case of an alien who departed the United States after having been issued an Authorization for parole of an Alien into the United States (Form I–512), and who returns to the United States in accordance with the conditions of that document, the physical presence in the United States requirement of section 202(b)(1) of Pub. L. 105–100 is tolled while the alien is outside the United States pursuant to the issuance of the Form I–512.

(3) *Request for parole authorization from outside the United States.* In the case of an alien who is outside the United States and submits an application for parole authorization in accordance with paragraph (k)(2) of this section, and such application for parole authorization is granted by the Service, the physical presence in the United States provisions of section 202(b)(1) of Pub. L. 105–100 is tilled from the date the application is received at the Texas Service Center until the alien is paroled into the United States pursuant to the issuance of the Form I–512.

(Approved by the Office of Management and Budget under Control Number 1115–0221.)

PART 274A—CONTROL OF EMPLOYMENT OF ALIENS

10. The authority citation for part 274a continues to read as follows:

Authority: 8 U.S.C. 1101, 1103, 1324a; 8 CFR part 2.

§ 274a.12 [Amended]

11. In § 274a.12, paragraph (c)(9) is amended in the second sentence by revising the term ''Employment authorization'' to read: ''Except as provided in § 245.13(j) of this chapter, employment authorization''.

§ 274a.13 [Amended]

12. In § 274a.13, paragraph (d) is amended in the first sentence by revising the phrase ''§ 274a.12(c)(8), which is governed by paragraph (a)(2) of this section, and § 274a.12(c)(9) in so far as it is governed by § 245.13(j) of this chapter''.

PART 299—IMMIGRATION FORMS

13. The authority citation for part 299 continues to read as follows:

Authority: 8 U.S.C. 1101, 1103; 8 CFR part 2.

14. Section 299.1 is amended in the table by:

a. Revising the entry for Form ''I–290C'', and by

b. Adding the entry for Form ''I–485 Supplement B'' in proper numerical sequence, to read as follows:

§ 299.1 Prescribed forms.

* * * * *

Form No.	Edition date	Title
* * *	*	* * *
I–290C	03–01–98	Notice of Certification.
* * *	*	* * *
I–485 Supplement B	03–01–98	NACARA Supplement to Form I–485 Instructions.
* * *	*	* * *

15. Section 299.5 is amended in the table by adding the entry for Form ''I–485 Supplement B'' in proper numerical sequence, to read as follows:

§ 299.5 Display of control numbers.

* * * * *

INS form No.	INS form title	Currently assigned OMB control No.
* * *	*	*
I–485 Supplement B	NACARA Supplement to Form I–485 Instructions	1115–0221
* * *	*	*

Dated: May 12, 1998.

Janet Reno,

Attorney General.

[FR Doc. 98–13246 Filed 5–20–98; 8:45 am]

BILLING CODE 4410–10–M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 98–NM–40–AD; Amendment 39–10534; AD 98–11–07]

RIN 2120–AA64

Airworthiness Directives; Dornier Model 328–100 Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Final rule.

SUMMARY: This amendment adopts a new airworthiness directive (AD), applicable to certain Dornier Model 328–100 series airplanes, that requires a one-time inspection of the double shuttle valve in the upper fuselage fairing for incorrectly labeled part numbers, and corrective actions, if necessary. This amendment is prompted by issuance of mandatory continuing airworthiness information by a foreign civil airworthiness authority. The actions specified by this AD are intended to ensure replacement of the double shuttle valves when they have reached their maximum life limit; incorrectly labeled part numbers of the double shuttle valves that are not replaced could result in the failure of the roll control spoilers, and, consequently, lead to reduced controllability of the airplane.

DATES: Effective June 25, 1998.

The incorporation by reference of certain publications listed in the regulations is approved by the Director of the Federal Register as of June 25, 1998.

ADDRESSES: The service information referenced in this AD may be obtained from FAIRCHILD DORNIER, DORNIER Luftfahrt GmbH, P.O. Box 1103, D–82230 Wessling, Germany. This information may be examined at the Federal Aviation Administration (FAA), Transport Airplane Directorate, Rules Docket, 1601 Lind Avenue, SW., Renton, Washington; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

FOR FURTHER INFORMATION CONTACT: Norman B. Martenson, Manager, International Branch, ANM–116, FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington 98055–4056; telephone (425) 227–2110; fax (425) 227–1149.

SUPPLEMENTARY INFORMATION: A proposal to amend part 39 of the Federal Aviation Regulations (14 CFR part 39) to include an airworthiness directive (AD) that is applicable to certain Dornier Model 328–100 series airplanes was published in the **Federal Register** on March 20, 1998 (63 FR 13577). That action proposed to require a one-time inspection of the double shuttle valve in the upper fuselage fairing for incorrectly labeled part numbers, and corrective actions, if necessary.

Comments

Interested persons have been afforded an opportunity to participate in the making of this amendment. No comments were submitted in response to the proposal or the FAA's determination of the cost to the public.

Conclusion

The FAA has determined that air safety and the public interest require the adoption of the rule as proposed.

Cost Impact

The FAA estimates that 50 airplanes of U.S. registry will be affected by this AD. It will take approximately 1 work hour per airplane to accomplish the required inspection at an average labor rate of $60 per work hour. Based on this figure, the cost impact of the inspection required by this AD on U.S. operators is estimated to be $3,000, or $60 per airplane.

The cost impact figure discussed above is based on assumptions that no operator has yet accomplished any of the requirements of this AD action, and that no operator would accomplish those actions in the future if this AD were not adopted.

Regulatory Impact

The regulations adopted herein will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with Executive Order 12612, it is determined that this final rule does

not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

For the reasons discussed above, I certify that this action (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) 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 final evaluation has been prepared for this action and it is contained in the Rules Docket. A copy of it 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, Incorporation by reference, 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:

98–11–07 Dornier Luftfahrt GmbH: Amendment 39–10534. Docket 98–NM–40–AD.

Applicability: Model 328–100 series airplanes, serial numbers 3005 through 3086 inclusive; certificated in any category.

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 (c) 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 ensure replacement of the double shuttle valves when they have reached their maximum life limit, accomplish the following:

(a) Within 30 days after the effective date of this AD, perform a one-time visual inspection of the double shuttle valve in the upper fuselage fairing to determine if the part number of the valve is labeled correctly, in accordance with Dornier Service Bulletin SB–328–27–236, Revision 1, dated November 5, 1997.

(b) If the inspection required by paragraph (a) of this AD reveals that the installed double shuttle valve is labeled incorrectly, prior to further flight, accomplish paragraphs (b)(1) and (b)(2) of this AD, in accordance with Dornier Service Bulletin SB–328–27–236, Revision 1, dated November 5, 1997.

(1) Revise the valve identification label to correctly identify the part number of the double shuttle valve, and delete any reference to operating pressure (i.e., BAR 205).

(2) Verify that the installed valve is within the limits specified for that particular part number in accordance with the service bulletin. If the installed double shuttle valve is outside the limits, prior to further flight, replace the double shuttle valve with a new part.

(c) 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, International Branch, ANM–116, FAA, Transport Airplane Directorate. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, International Branch, ANM–116.

Note 2: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the International Branch, ANM–116.

(d) Special flight permits may be issued in accordance with sections 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.

(e) The actions shall be done in accordance with Dornier Service Bulletin SB–328–27–236, Revision 1, dated November 5, 1997. This incorporation by reference was approved by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. Copies may be obtained from FAIRCHILD DORNIER, DORNIER Luftfahrt GmbH, P.O. Box 1103, D–82230 Wessling, Germany. Copies may be inspected at the FAA, Transport Airplane Directorate, 1601 Lind Avenue, SW., Renton, Washington; or at the Office of the Federal Register, 800 North Capitol Street, NW., suite 700, Washington, DC.

Note 3: The subject of this AD is addressed in German airworthiness directive 1997–321/2, dated January 15, 1998.

(f) This amendment becomes effective on June 25, 1998.

Issued in Renton, Washington, on May 13, 1998.

John J. Hickey,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 98–13312 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 178

[Docket No. 90F–0310]

Indirect Food Additives: Adjuvants, Production Aids, and Sanitizers

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the food additive regulations to provide for the safe use of 1,11-(3,6,9-trioxaundecyl)bis-3-(dodecylthio)propionate as an antioxidant for can end cements used in contact with food. This action is in response to a petition filed by Goodyear Tire and Rubber Co.

DATES: The regulation is effective May 21, 1998. Submit written objections and requests for a hearing by June 22, 1998.

ADDRESSES: Submit written objections to the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: Vir D. Anand, Center for Food Safety and Applied Nutrition (HFS–215), Food and Drug Administration, 200 C St. SW., Washington, DC 20204, 202–418–3081.

SUPPLEMENTARY INFORMATION: In a notice published in the **Federal Register** of October 30, 1990 (55 FR 45656), FDA announced that a food additive petition (FAP 0B4223) had been filed by Goodyear Tire and Rubber Co., Akron, OH 44316–0001 (presently c/o Keller and Heckman, 1001 G St. NW., suite 500 West, Washington, DC 20001). The petition proposed to amend the food additive regulations in § 178.2010 *Antioxidants and/or stabilizers for polymers* (21 CFR 178.2010) to provide for the safe use of 1,11-(3,6,9-trioxaundecyl)bis-3-(dodecylthio)propionate as an antioxidant for can end cements used in contact with food.

FDA has evaluated data in the petition and other relevant material. Based on this information, the agency

concludes that the proposed use of the additive is safe, that the additive will achieve its intended technical effect, and therefore, that the regulations in § 178.2010 should be amended as set forth below.

In accordance with § 171.1(h) (21 CFR 171.1(h)), the petition and the documents that FDA considered and relied upon in reaching its decision to approve the petition are available for inspection at the Center for Food Safety and Applied Nutrition by appointment with the information contact person listed above. As provided in § 171.1(h), the agency will delete from the documents any materials that are not available for public disclosure before making the documents available for inspection.

The agency has carefully considered the potential environmental effects of this action. FDA has concluded that the action will not have a significant impact on the human environment, and that an environmental impact statement is not required. The agency's finding of no significant impact and the evidence supporting that finding, contained in an environmental assessment, may be seen in the Dockets Management Branch (address above) between 9 a.m. and 4 p.m., Monday through Friday.

Any person who will be adversely affected by this regulation may at any time on or before June 22, 1998, file with the Dockets Management Branch (address above) written objections thereto. Each objection shall be separately numbered, and each numbered objection shall specify with particularity the provisions of the regulation to which objection is made and the grounds for the objection. Each numbered objection on which a hearing is requested shall specifically so state. Failure to request a hearing for any particular objection shall constitute a waiver of the right to a hearing on that objection. Each numbered objection for which a hearing is requested shall include a detailed description and analysis of the specific factual information intended to be presented in support of the objection in the event that a hearing is held. Failure to include such a description and analysis for any particular objection shall constitute a waiver of the right to a hearing on the objection. Three copies of all documents shall be submitted and shall be identified with the docket number found in brackets in the heading of this document. Any objections received in response to the regulation may be seen in the Dockets Management Branch between 9 a.m. and 4 p.m., Monday through Friday.

List of Subjects in 21 CFR Part 178

Food additives, Food packaging.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Director, Center for Food Safety and Applied Nutrition, 21 CFR part 178 is amended as follows:

PART 178—INDIRECT FOOD ADDITIVES: ADJUVANTS, PRODUCTION AIDS, AND SANITIZERS

1. The authority citation for 21 CFR part 178 continues to read as follows:

Authority: 21 U.S.C. 321, 342, 348, 379e.

2. Section 178.2010 is amended in the table in paragraph (b) by alphabetically adding a new entry under the headings ''Substances'' and ''Limitations'' to read as follows:

§ 178.2010 Antioxidants and/or stabilizers for polymers.

* * * * *

(b) * * *

Substances	Limitations
* * *	* * * *
1, 11-(3, 6, 9-Trioxaundecyl) bis-3-(dodecylthio) propionate (CAS Reg. No. 64253–30–1).	For use only as provided in § 175.300(b)(3)(xxxi) of this chapter at 4.0 parts per 100 parts rubber.
* * *	* * * *

Dated: May 11, 1998.

L. Robert Lake,

Director, Office of Policy, Planning and Strategic Initiatives, Center for Food Safety and Applied Nutrition.

[FR Doc. 98–13469 Filed 5–20–98; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 201

[Docket No. 78N–036L]

RIN 0910–AA01

Package Size Limitation for Sodium Phosphates Oral Solution and Warning and Direction Statements for Oral and Rectal Sodium Phosphates for Over-the-Counter Laxative Use

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is issuing a final rule to limit the container size for sodium phosphates oral solution (dibasic sodium phosphate/monobasic sodium phosphate oral solution) to not greater than 90 milliliters (mL) (3 ounces (oz)) when used as an over-the-counter (OTC) laxative drug product. FDA is limiting the container size because of reports of deaths associated with an overdosage of sodium phosphates oral solution when the product was packaged in a larger-size container and a larger than intended dose was ingested inadvertently. The agency is also requiring warning and direction statements to inform consumers that exceeding the recommended dose of oral and rectal sodium phosphates products in a 24-hour period can be harmful. This final rule is part of the ongoing review of OTC drug products conducted by FDA.

DATES: The regulation is effective June 22, 1998, however compliance with

§ 201.307(b)(2) and (b)(3) is not mandatory until September 18, 1998.

FOR FURTHER INFORMATION CONTACT: Cheryl A. Turner, Center for Drug Evaluation and Research (HFD–560), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301–827–2222.

SUPPLEMENTARY INFORMATION:

I. Background

In the **Federal Register** of March 21, 1975 (40 FR 12902), FDA published, under § 330.10(a)(6) (21 CFR 330.10(a)(6)), an advance notice of proposed rulemaking to establish a monograph for OTC laxative, antidiarrheal, emetic, and antiemetic drug products, together with the recommendations of the Advisory Review Panel on OTC Laxative, Antidiarrheal, Emetic, and Antiemetic Drug Products (the Panel), which was the Advisory Review Panel responsible for evaluating data on the active ingredients in these classes. The Panel recommended monograph status for phosphate salts, such as sodium phosphates oral solution (40 FR 12902 at 12940), but did not recommend any container size limitations.

The agency's proposed regulation, in the form of a tentative final monograph, for OTC laxative drug products was published in the **Federal Register** of January 15, 1985 (50 FR 2124). The agency also proposed monograph status for sodium phosphates oral solution (50 FR 2124 at 2152 and 2155), but did not recommend any container size limitations. The agency proposed the following dosage for sodium phosphates oral solution for adults and children 12 years of age and over: 3.42 to 7.56 grams (g) of dibasic sodium phosphate and 9.1 to 20.2 g of monobasic sodium phosphate [1] in a single daily dose. (See proposed § 334.58(d)(5)(i) (21 CFR 334.58(d)(5)(i)), 50 FR 2124 at 2155.) In addition to its use as an OTC laxative for the relief of occasional constipation, sodium phosphates oral solution [2] is used as part of a bowel cleansing regimen in preparing a patient for surgery or for preparing the colon for x-ray or endoscopic examination. (See proposed § 334.80(a)(2), 50 FR 2124 at 2157.) Sodium phosphates oral solution and sodium phosphates enema [3], respectively, are the current United States Pharmacopeia (USP) names for the oral and rectal dosage forms of the combination of sodium phosphates ingredients.

In the **Federal Register** of March 31, 1994 (59 FR 15139), the agency proposed to amend the tentative final monograph for OTC laxative drug products to limit the OTC container size for sodium phosphates oral solution to not greater than 90 mL. The agency also proposed a warning for all oral and rectal dosage forms of sodium phosphates products to inform consumers not to exceed the recommended dosage unless directed by a doctor. Interested persons were invited to submit written comments on the proposed regulation and on the agency's economic impact determination by May 31, 1994.

In response to the proposal, two manufacturers of laxative drug products submitted comments. Neither comment addressed the agency's economic impact determination. Copies of these comments are on public display in the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857. Additional information that has come to the agency's attention since publication of the proposal is also on public display in the Dockets Management Branch.

In the proposal, the agency discussed its reasons for limiting the package size for sodium phosphates oral solution (59 FR 15139). The agency noted that the major trade product containing sodium phosphates oral solution was marketed in 45-mL, 90-mL, and 240-mL bottles. The purgative dose or dose used for colonoscopy is 45 mL. Because the product was available in three sizes, the manufacturer's labeling advised physicians to prescribe by volumes and not to prescribe by the bottle and not to exceed the recommended dosage, as serious side effects may occur. Despite this labeling, the multiple container sizes available in the marketplace have caused consumer confusion and appear to have been involved in several consumer deaths.

The agency determined that the OTC availability of the 240-mL container of sodium phosphates oral solution creates a potential safety risk, particularly for elderly persons who are likely to use the product for bowel cleansing prior to surgery or a diagnostic procedure involving the colon. Because of the reported cases of accidental overdosing and the confusion that has occurred between 240-mL and 90-mL container sizes, the agency proposed that the 240-mL size container of sodium phosphates oral solution should no longer remain in the OTC marketplace. In the interest of safety, the agency proposed to limit the maximum OTC container size for this product to 90 mL.

The agency proposed to include the package size limitation and warning in the monograph for OTC laxative drug products. However, that monograph has not been finalized to date. Because of the potential safety risk involved, the agency has decided to finalize both the package size limitation and several new warning and direction statements prior to completion of the final monograph for OTC laxative drug products. The agency has decided to include this information in part 201 (21 CFR part 201) at this time and to incorporate it into the final monograph for OTC laxative drug products at a later date.

In the **Federal Register** of February 27, 1997 (62 FR 9024), FDA proposed to establish a standardized format for the labeling of OTC drug products. Until the proposal is finalized, manufacturers, distributors, and packagers must comply with the final rule published herein and all other currently applicable labeling regulations. The agency will eventually use the final labeling rule to incorporate the information included herein in part 201 into the final monograph for OTC laxative drug products.

II. The Agency's Conclusions on the Comments

1. One comment stated that, according to the USP 22 (Ref. 1), the current terminology for sodium phosphate is monobasic sodium phosphate and for sodium biphosphate it is dibasic sodium phosphate. The comment stated that the tentative final monograph should be amended accordingly.

Under agency regulations in 21 CFR 299.4(e), the established name of a drug is the current compendial name or the USAN (U.S. Adopted Names Council) adopted name listed in the USP Dictionary of USAN and International Drug Names. Both the U.S. Pharmacopeia 23/National Formulary 18 (Ref. 2) and the USP Dictionary of USAN and International Drug Names, 1997 (Ref. 3) list the current name for sodium phosphate as ''dibasic sodium phosphate,'' and for sodium

[1] In the tentative final monograph for OTC laxative drug products, published in the **Federal Register** of January 15, 1985 (50 FR 2124), and in the proposed rule for package size limitation for OTC laxative drug products published in the **Federal Register** of March 31, 1994 (59 FR 15139), the agency referred to dibasic sodium phosphate as ''sodium phosphate,'' and monobasic sodium phosphate as ''sodium biphosphate.'' The current nomenclature in the *USP Dictionary of USAN and International Drug Names, 1997* is ''dibasic sodium phosphate'' and ''monobasic sodium phosphate,'' respectively. This final rule uses the current nomenclature.

[2] Sodium phosphates oral solution is the official name for a solution of dibasic sodium phosphate and monobasic sodium phosphate in the *U.S. Pharmacopeia 23/National Formulary 18, 1995*.

[3] Sodium phosphates enema is the official name for a solution of dibasic sodium phosphate and monobasic sodium phosphate in the *U.S. Pharmacopeia 23/National Formulary 18, 1995*.

biphosphate as ''monobasic sodium phosphate.'' (See footnote 1, supra.) It appears that the comment inadvertently reversed the names of the ingredients.

2. One comment stated that the agency's proposal that the final rule be effective 30 days after its publication in the **Federal Register** is insufficient time. The comment argued that 30 days would not be enough time for relabeling of its sodium phosphates products and requested that the final rule be effective 120 days after its publication in the **Federal Register**.

The agency is instituting a split effective date for this final rule. Because of the potential serious safety risk involved, the agency has determined that initial introduction or initial delivery for introduction into interstate commerce of any container size of sodium phosphates oral solution greater than 90 mL should cease as soon as possible (within 30 days of this final rule). However, the agency concurs with the comment that manufacturers need more than 30 days to relabel these drug products and is granting the 120 days requested by the comment. Because of the potential serious safety risks, the agency has determined that manufacturers need to work promptly to relabel their products. The agency is providing manufacturers the option to use supplementary labeling (e.g., stick-on labeling) to add the new warning and direction information to currently manufactured products not yet introduced into interstate commerce or on package labeling that has not yet been incorporated into the manufacturing process. If manufacturers choose not to use stick-on labeling, they are encouraged to have new labeling containing the new warning and direction information printed as expeditiously as possible in the interest of safe use of these products.

3. One comment stated that sodium phosphates oral solution should not be marketed in packages containing more than 45 mL. The comment argued that 45 mL of this product equals the ''single daily dose'' of solution generally recognized as safe and effective for use as a laxative and bowel cleansing agent in the tentative final monograph. The comment provided data to show that taking more than this amount has been shown to cause significant changes in blood levels of sodium, potassium, phosphate, chloride, and calcium, thereby imposing a risk of serious injury (Refs. 4, 5, and 6).

The agency does not agree with the comment that packages containing more than 45 mL of sodium phosphates oral solution should not be marketed. Problems that previously occurred involved confusion resulting from the availability of a 240-mL container size (59 FR 15139). (In 1993, the manufacturer of the major trade product containing this solution ceased manufacture and initiated a market withdrawal of the 240-mL container size.) The oral solution is currently marketed in 45-mL and 90-mL containers. The agency has not received any reports that a one-time 90 mL dose has resulted in a death or a serious adverse reaction requiring medical treatment.

The agency has reviewed the submitted data (Refs. 4, 5, and 6) and agrees that taking more than 45 mL of sodium phosphates solution over a 10- to 12-hour period can result in significant changes in electrolytes and may impose a risk of serious injury. (See comment 4 in section II of this document.) Therefore, the agency is requiring specific warning and direction statements to ensure that the correct dose is used and that consumers do not use more than the recommended dose in a 24-hour period. The agency proposed to amend the tentative final monograph for OTC laxative drug products to include in § 334.58(c)(2)(iv) the following warning for oral and rectal dosage forms of sodium phosphates products: ''Do not exceed recommended dose unless directed by a doctor. Serious side effects many occur from excess dosage'' (59 FR 15139).

In this final rule, the agency is revising the proposed warning by adding 24-hour dosing information and by simplifying the language. The agency is also requiring separate warnings for oral and rectal enema drug products. For oral sodium phosphates drug products, the new warning states: ''Taking more than the recommended dose in 24 hours can be harmful.'' For rectal sodium phosphates drug products, the new warning states: ''Using more than one enema in 24 hours can be harmful.'' Both warnings must be in boldface type and appear as the first statement under the heading ''Warnings.'' (See comment 5 in section II of this document.)

The agency is also adding new directions in boldface type immediately preceding the dosage information, which state: ''Do not'' (''take'' or ''use'') ''more unless directed by a doctor. See Warnings.'' (See comment 4 in section II of this document.) The new directions appear in § 201.307(b)(3)(i).

The agency notes that sodium phosphates oral solution is available for general laxative use for relief of occasional constipation at a single daily dose of 20 mL to 45 mL for adults and children 12 years of age and over. Thus, a larger size container (90 mL) may be more convenient for consumers to purchase and have available for future use. The agency is also aware that the 45-mL and 90-mL container sizes are often recommended and prescribed by physicians for bowel cleansing prior to surgery and diagnostic procedures of the colon. Accordingly, the agency is allowing the 90-mL container of sodium phosphates oral solution to remain on the OTC market. However, in an effort to prevent consumers from taking an entire 90-mL container in 1 day (24 hours), the agency is adding additional statements in the directions in § 201.307(b)(3)(ii) to inform consumers how much of the oral solution may be taken as a single daily dose and not to take more than the recommended daily dose in a 24-hour period. The agency has also revised the format for stating children's ages from that proposed in § 334.58(d)(5)(i) of the tentative final monograph (50 FR 2124 at 2155). The directions now state:

Adults and children 12 years of age and over: Oral dosage is dibasic sodium phosphate 3.42 to 7.56 grams (g) and monobasic sodium phosphate 9.1 to 20.2 g (20 to 45 mL dibasic sodium phosphate/monobasic sodium phosphate oral solution) as a single daily dose. ''Do not take more than 45 mL (9 teaspoonfuls or 3 tablespoonfuls) in a 24-hour period.''

Children 10 and 11 years of age: Oral dosage is dibasic sodium phosphate 1.71 to 3.78 g and monobasic sodium phosphate 4.5 to 10.1 g (10 to 20 mL dibasic sodium phosphate/monobasic sodium phosphate oral solution) as a single daily dose. ''Do not take more than 20 mL (4 teaspoonfuls) in a 24-hour period.''

Children 5 to 9 years of age: Oral dosage is dibasic sodium phosphate 0.86 to 1.89 g and monobasic sodium phosphate 2.2 to 5.05 g (5 to 10 mL dibasic sodium phosphate/monobasic sodium phosphate oral solution) as a single daily dose. ''Do not take more than 10 mL (2 teaspoonfuls) in a 24-hour period.'' Children under 5 years of age: ask a doctor.

The agency notes that the directions for sodium phosphates oral solution contain separate dosages for children 10 and 11 years of age and for children 5 to 9 years of age. These age ranges are not consistent with age ranges used for the majority of OTC laxative drug products, which recommend dosages for children 6 to 11 years of age. Therefore, elsewhere, in this issue of the **Federal Register**, the agency is proposing to revise the directions for sodium phosphates oral solution to limit the OTC use of these products to children 6 years of age and above.

The proposed directions state:

* * * Children 6 to 9 years of age: Oral dosage is dibasic sodium phosphate 0.86 to 1.89 g and monobasic sodium phosphate 2.2 to 5.05 g (5 to 10 mL dibasic sodium phosphate/monobasic sodium phosphate oral

solution) as a single daily dose. 'Do not take more than 10 mL (2 teaspoonfuls) in a 24-hour period.' Children under 6 years of age: ask a doctor.

4. One comment requested that sodium phosphates oral solution products bear a warning against consuming more than 45 mL in a 24-hour period unless directed by a physician. The comment contended that there are potentially serious health problems associated with high doses of this product. The comment submitted data to show that consuming more that 45 mL of sodium phosphates oral solution in 24 hours has resulted in significant changes in blood levels of sodium, potassium, phosphate, chloride, and calcium, thereby imposing a risk of serious injury (Refs. 4, 5, and 6).

The agency has reviewed the submitted data and agrees that ingesting more that 45 mL of sodium phosphates oral solution in a 24-hour period may be harmful. Clarkston et al. (Ref. 4) compared a polyethylene glycol (PEG) based gastrointestinal lavage to a sodium phosphates oral regimen. In this randomized trial, 26 subjects took 4 liters (L) of the PEG solution and 25 subjects took two 45-mL doses of sodium phosphates oral solution 11 hours apart. The subjects had a chemistry panel and ionized calcium done prior to taking the drug and on the morning of the colonoscopy. The results indicated that the sodium phosphates solution caused a decrease in ionized serum calcium and serum potassium, with concomitant increases in phosphate. The investigators stated that the sodium phosphates oral regimen resulted in statistically significant changes in serum sodium, potassium, phosphorus, and calcium ($p < 0.01$). The investigators concluded that the risk of symptoms of hypocalcemia must be considered due to the abnormal low levels of ionized calcium that frequently occur with this regimen.

Vanner et al. (Ref. 5) compared a standard PEG based gastrointestinal solution to a sodium phosphates oral solution prior to colonoscopy. In this parallel, single-blinded, randomized study, 54 subjects received two 45-mL doses of the sodium phosphates oral solution 11 hours apart, and 48 subjects received 4 L of the PEG solution. The subjects had blood tests on admission and the morning of the procedure. The authors concluded that the sodium phosphates oral solution was safe and effective because serial measurements of blood tests, postural pulse, and blood pressure changes did not reveal any clinically significant changes in intravascular volume. One ''syncopal episode'' occurred in the sodium phosphates group. The authors mentioned that the subject's vital signs did not appear to indicate that hypovolemia (abnormally decreased volume of circulating plasma) was the cause. The authors reported that hyperphosphatemia occurred with sodium phosphates, but serum phosphate values returned to normal within 24 hours, and no concomitant decrease in calcium was seen. They added that histological assessment for possible preparation-induced changes revealed no difference between the two drugs.

The agency notes that numerous induced electrolyte abnormalities occurred in this study. The data showed statistically significant decreases in potassium and increases in hematocrit, sodium, chloride, osmolality, and phosphate. Extreme serum phosphate levels reached 11.6 milligrams/deciliter (mg/dL) in the sodium phosphates group and 4.7 mg/dL in the PEG group; normal values are 2.5 to 4.1 mg/dL. In hyperphosphatemia, excessive complexing of calcium with phosphate may contribute to a decrease in plasma ionized calcium, which results in hypocalcemia. Calcium levels were not reported for the entire sodium phosphates group nor was the risk of hypokalemia mentioned. The agency notes that the postural changes in pulse, systolic blood pressure, and the one ''syncopal episode'' were most likely due to decreased intravascular volume in subjects in the sodium phosphates group.

Because elevated phosphate levels are known to occur with sodium phosphates use, 15 subjects were randomly selected to have serum phosphate and calcium levels measured at 4 p.m. on the day of colonoscopy and at 8 a.m. the following day. Seven of the fifteen subjects received the sodium phosphates regimen. Vanner et al. reported that 2 hours after the second dose, the mean serum phosphorus was 7.2 mg/dL (nearly twice the pre-study value of 3.7 mg/dL), while the total calcium values continued to decline for at least 24 hours after the dose was taken.

The agency believes that the Vanner et al. study showed that postural increases in pulse, decreases in systolic blood pressure, and serum electrolyte and plasma volume shifts were greater in the sodium phosphates group than in the PEG group. The incidence of postural elevation in heart rate, indicating significant reduction in intravascular volume, was also three times higher in the sodium phosphates group than in the PEG group. Because of the small sample size, the fact that none of the study subjects died or had serious side effects that required hospitalization cannot be interpreted to mean that two 45-mL doses of sodium phosphates oral solution are safe to ingest without a physician's supervision.

Warner and DiPalma (Ref. 6) stated that sodium phosphates oral solution is extremely popular for use as a bowel cleansing agent because it is effective, easy to administer, and well tolerated. However, they contended that little data are available concerning its safety. They mentioned that the majority of trials evaluating the product for use as a bowel cleanser have not systematically monitored electrolytes. They asserted that the solubility product of calcium and phosphate, when exceeded, leads to soft tissue calcification in areas where an alkaline internal environment enhances calcium phosphate salt deposit, primarily in the kidneys, heart, blood vessel, cornea, lungs, and gastric mucosa. They stated that the normal calcium-phosphate product is 40 mg/dL, which is tightly regulated through absorption, excretion, and intracellular/extracellular ion shifts; and that the in vitro solubility product of calcium is 58 mg/dL, well above the normal value (Ref. 6). Warner and DiPalma mentioned that Vanner et al. (Ref. 5) and Kolts (Ref. 7) have presented limited data to show phosphate levels rising to as high as 7 mg/dL with relatively unchanged serum calcium values. According to Warner and DiPalma, the increase in phosphate levels appeared quite transient, but because sampling was so infrequent, it is impossible to ascertain whether even these high values represent the peak phosphate concentrations after administration of sodium phosphates oral solution.

Kolts (Ref. 8) responded to Warner and DiPalma, and argued that sodium phosphates oral solution should be the preparation of choice for most endoscopy outpatients due to its low cost, comfort for the patient, and low incidence of adverse side events. Kolts stated that the sodium phosphates oral solution used in his study (Ref. 7) had been sold OTC for more than 100 years and the manufacturer had not reported any serious side effects, except when the solution was taken in massive overdoses or if used when contraindicated. Kolts added that there were no reports of adverse events such as ectopic calcification in the literature from 1966 to 1993 from the use of phosphate catharsis in people with normal renal function. Kolts concluded that his (Ref. 7) and Vanner's (Ref. 5) studies documented the minor changes

in clinically relevant electrolytes as well as the lack of adverse symptoms from sodium phosphates oral solution.

The agency finds that the data show that sodium phosphates oral solution can cause alterations in serum levels of sodium, potassium, phosphate, chloride, and calcium. In some people, such changes can be life-threatening. The agency has particular concerns about hypocalcemia occurring due to its reported frequency when two 45-mL doses of sodium phosphates oral solution are given over a 24-hour period. The reduction of calcium levels reflects changes in ionized calcium (Ref. 9). Hypocalcemia with subsequent low levels of ionized calcium may result in neuromuscular irritability, heart block, and cardiovascular failure (Ref. 9).

In the tentative final monograph for OTC laxative drug products (50 FR 2124 at 2155), the agency proposed a maximum single daily oral dose of 7.56 g of dibasic sodium phosphate and 20.2 g of monobasic sodium phosphate. The major manufacturer of sodium phosphates products recommends (as part of a bowel cleansing regimen in preparation for surgery or preparation of the colon for x-ray or endoscopic examination) (Ref. 10) that 45 mL be given at 7 p.m. and again at 6 a.m. the following morning. The agency notes that 0.9 g/5 mL of dibasic sodium phosphate is equivalent to 17.1 to 18.9 g/100 mL of sodium phosphates oral solution, and that 2.4 g/5 mL of monobasic sodium phosphate is equivalent to 45.6 to 50.4 g/100 mL of sodium phosphates oral solution according to the USP 23 (Ref. 2). Therefore, over an 11-hour period, 90 mL of solution (approximately 16.2 g of dibasic sodium phosphate and 43.2 g of monobasic sodium phosphate) containing 9.9 g of sodium could be consumed. The manufacturer of this product has not submitted sufficient data to demonstrate the safety of more than 45 mL of this solution in a 24-hour period (Ref. 11). Thus, the agency concludes that the safe oral use of more than 7.56 g of dibasic sodium phosphate and 20.2 g of monobasic sodium phosphate in a 24-hour period has not been demonstrated at this time. Therefore, the agency will not include a greater dosage in a 24-hour period in the OTC or professional labeling in the final monograph for OTC laxative drug products, which will be published in a future issue of the **Federal Register**.

The agency agrees with the comment that the labeling for sodium phosphates oral solution should include a warning not to ingest more than the recommended dose in a 24-hour period. Accordingly, the agency is including the following warning in § 201.307(b)(2)(i) for oral products that contain sodium phosphates: ''Taking more than the recommended dose in 24 hours can be harmful.'' The sentence is required to appear in boldface type as the first statement under the heading ''Warnings.'' The agency is also requiring in § 201.307(b)(3)(i) that the directions for oral and rectal sodium phosphates products contain the following statements in boldface type immediately preceding the dosage information: ''Do not'' (''take'' or ''use'') ''more unless directed by a doctor. See Warnings.'' (See comment 5 in section II of this document.) These additional statements are intended to refer consumers to the warnings when they read the directions for the product.

5. One comment disagreed with the proposed warning in § 334.58(c)(2)(iv) for rectal enema sodium phosphates drug products, which states: ''Do not exceed recommended dose unless directed by a doctor. Serious side effects may occur from excess dosage.'' The comment argued that the agency provided no concrete or specific evidence to support this warning. The comment stated that its sodium phosphates enema contains 19 g/118 mL (equivalent to 16 g/100 mL) of monobasic sodium phosphate and 7 g/118 mL (equivalent to 7 g/100 mL) of dibasic sodium phosphate. In contrast, the oral product contains 2.4 g/5 mL (equivalent to 48 g/100 mL) of monobasic sodium phosphate and 0.9 g/5 mL (equivalent to 18 g/100 mL) of dibasic sodium phosphate. The comment stated that because the phosphate concentration of the enema is only one-third that of the oral product, use of the enema is not likely to result in overdosage. The comment added that an overdosage is unlikely to occur due to the way enemas are used and the results they produce. The comment mentioned that the enema product is clearly labeled ''Not intended for oral consumption,'' and that the current labeling clearly states the appropriate dosage. Thus, the comment concluded that the warning should not be required for sodium phosphates enema products. Another comment stated that the dosage and administration section of products containing sodium phosphates should be allowed to contain statements similar to the following proposed warning: ''Do not exceed recommended dose unless directed by a doctor. Serious side effects may occur from excess dosage.'' The comment indicated that such statements should be allowed, but do not need to be included in the final rule.

The agency notes that the first comment made an error in its statement of the amount of dibasic sodium phosphate per 100 mL. It should have been approximately 6 g/mL which is consistent with USP 23 (Ref. 2), which states that each 100 mL of sodium phosphates enema solution contains not less than 5.7 g and not more than 6.3 g of dibasic sodium phosphate.

The agency is aware of numerous reports of misuse of sodium phosphates enemas that resulted in adverse effects (Refs. 12 through 23). Wason et al. (Ref. 12) reported the case of a normal 5-month-old child who was given an entire adult sodium phosphates enema by her mother. Within 30 minutes, the child became extremely ill; consciousness decreased; and shock, hyperphosphatemia, hypocalcemia, and acidosis developed. The child was hospitalized and responded to intravenous (IV) fluid replacement and aluminum hydroxide gel. Oxnard, O'Bell, and Grupe (Ref. 13) reported that a 4-year-old child with chronic renal failure became profoundly hyperphosphatemic and hypocalcemic after receiving an entire adult sodium phosphates enema. The child developed muscle twitching, acidosis, severe diarrhea, and tachycardia, and was hospitalized, subsequently responding to IV calcium gluconate, calcium chloride, and sodium bicarbonate.

Other authors have reported that children (4 months to 2 1/2 years old) with gastrointestinal anomalies, such as Hirschsprung's disease (congenital megacolon), and chronic renal failure were at high risk for complications after the use of sodium phosphates enemas (Refs. 13 through 20). These children received varying amounts of adult or pediatric sodium phosphates enemas for constipation and bowel cleansing prior to surgery. Three of the children had cardiac arrest after the use of hypertonic sodium phosphates enemas (Refs. 17, 19, and 20). Martin et al. (Ref. 19) reported that an 11-month-old child died after receiving four adult sodium phosphates enemas. Loughnan and Mullins (Ref. 17) reported that a 9-month-old child suffered severe and permanent brain damage after receiving a pediatric sodium phosphates enema. Reedy and Zwiren (Ref. 20) reported that a 17-month-old child received two pediatric sodium phosphates enemas as a ''bowel prep'' on the day of surgery and was successfully resuscitated after experiencing cardiac arrest during induction of anesthesia. The authors noted that the child had received sodium phosphates enemas chronically but that a possible electrolyte imbalance was not suspected, and the child was not screened for any possible electrolyte problems prior to surgery.

Other authors (Refs. 21, 22, and 23) have reported acidosis, hypocalcemia, and hyperphosphatemia that occurred in adults and children after the use of sodium phosphates enema products. Davis et al. (Ref. 21) state that these products can cause electrolyte imbalances, which can cause severe reactions and could result in death, when administered in the recommended doses to individuals with normal renal function.

The agency is also aware of serious electrolyte imbalances occurring in individuals who used more than one sodium phosphates enema in a 24-hour period (Refs. 15, 16, 24, 25, and 26). Thus, an electrolyte imbalance can result from an excess dose of either the oral solution or the enema dosage form. Because of the serious side effects that can occur from overdosage, the agency considers it important to include information against exceeding the recommended dose of sodium phosphates drug products in both the warnings and directions sections of product labeling. The agency concludes that this information needs to be required, not just voluntarily included at a manufacturer's discretion.

III. References

The following references are on display in the Dockets Management Branch (address above) and may be seen by interested persons between 9 a.m. and 4 p.m., Monday through Friday.

1. The United Stated Pharmacopeia 22/ The National Formulary 17, The United States Pharmacopeial Convention Inc., Rockville, MD, pp. 1265–1267, 1989.

2. The United States Pharmacopeia 23/ The National Formulary 18, The United States Pharmacopeial Convention Inc., Rockville, MD, pp. 1428–1430, 1994.

3. United States Pharmacopeia Dictionary of United States Adopted Names and International Drug Names, The United States Pharmacopeial Convention Inc., Rockville, MD, p. 658, 1997.

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15. Honig, P. J., and P. G. Holtzapple, ''Hypocalcemic Tetany Following Hypertonic Phosphate Enemas,'' *Clinical Pediatrics*, 14:678–679, 1975.

16. Sotos, J. F. et al., ''Hypocalcemic Coma Following Two Pediatric Phosphate Enemas,'' *American Academy of Pediatrics*, 60:305–307, 1977.

17. Loughnan, P., and G. C. Mullins, ''Brain Damage Following a Hypertonic Phosphate Enema,'' *American Journal of Diseases of Children*, 131:1032, 1977.

18. Forman, J., H. J. Baluarte, and A. B. Gruskin, ''Hypokalemia After Hypertonic Phosphate Enemas,'' *Journal of Pediatrics*, 94:149–151, 1979.

19. Martin, R. R. et al., ''Fatal Poisoning From Sodium Phosphate Enema, Case Report and Experimental Study,'' *Journal of the American Medical Association*, 257:2190–2192, 1987.

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IV. Summary of Significant Changes From the Proposed Rule

The agency is making the following changes based on comments submitted in response to the proposal (59 FR 15139) and other relevant information that has come to the agency's attention. The agency had proposed to include the package size limitation and the labeling in the final monograph for OTC laxative drug products (proposed 21 CFR part 334). However, that final monograph has not been completed to date. Therefore, at this time the agency is including this information in part 201 subpart G, Specific Labeling Requirements for Specific Drug Products. New § 201.307 will be titled *Sodium phosphates; package size limitation, warnings, and directions for over-the-counter sale*. When the laxative final monograph is complete, it will incorporate the requirements in § 201.307. A summary of the changes made by the agency follows:

1. The package size limitation of 90 mL (3 oz) for sodium phosphates oral solution proposed in § 334.25 appears in § 201.307(b)(1) and is effective 30 days after date of publication of this final rule in the **Federal Register**. The relabeling requirements in § 201.307 are effective 120 days after date of publication of this final rule in the **Federal Register**. (See comment 2 in section II of this document.)

2. The agency has revised the warning for oral and rectal dosage forms of sodium phosphates proposed in § 334.58(c)(2)(iv). The agency is adding a new warning for oral sodium phosphates products, which appears in § 201.307(b)(2)(i) and states: ''Taking more than the recommended dose in 24 hours can be harmful.'' (See comment 5 in section II of this document.) The agency is adding a new warning for rectal sodium phosphates products, which appears in § 201.307(b)(2)(ii) and states: ''Using more than one enema in 24 hours can be harmful.'' These warnings must appear in boldface type and must be the first statement in product labeling under the heading ''Warnings.''

3. The agency is adding new directions in § 201.307(b)(3)(i) for oral and rectal sodium phosphates that state: ''Do not'' (''take'' or ''use'') ''more unless directed by a doctor. See Warnings.'' (See comment 4 in section II of this document.) These directions must be in boldface type and immediately precede the dosage information.

4. The agency is including specific directions in § 201.307(b)(3)(ii) that inform consumers not to take more than the recommended daily dose in a 24-hour period. (See comment 3 in section II of this document.)

V. The Agency's Final Conclusions on OTC Laxative Drug Products Containing Sodium Phosphates

The agency has determined that there is sufficient evidence to show that an overdose of sodium phosphates products can cause an electrolyte imbalance. This imbalance can occur if an excess dose of either the sodium phosphates oral solution or the sodium phosphates enema were used. This electrolyte imbalance can cause severe reactions and result in death. Accordingly, this final rule establishes a container size limit for oral sodium phosphates products and new warning and direction statements for OTC laxative drug product containing sodium phosphates. To better protect consumers who use products containing these ingredients, the agency concludes that the container size must be limited to 90 mL (3 oz). In addition, labeling needs to alert consumers not to exceed the recommended dose of an oral or rectal sodium phosphates product in a 24-hour period. Therefore, the agency is requiring the following warning for oral dosage forms of sodium phosphates in § 201.307(b)(2)(i): ''Taking more than the recommended dose in 24 hours can be harmful.'' The agency is also requiring a similar warning for rectal dosage forms of sodium phosphates in § 201.307(b)(2)(ii): ''Using more than one enema in 24 hours can be harmful.'' Furthermore, the agency is requiring that the directions for oral and rectal sodium phosphates products in § 201.307(b)(3)(i) state: ''Do not'' (''take'' or ''use'') ''more unless directed by a doctor. See Warnings.'' These additional statements are intended to refer consumers to the warnings when they read the directions for the product. Because of the dire consequences that can occur from an overdose of sodium phosphates, the warnings are required to appear in boldface type as the first sentence under the heading ''Warnings.'' The direction statements are required to appear in boldface type immediately preceding the dosage information. In addition, the agency is including specific directions that inform consumers not to take more than the recommended daily dose in a 24-hour period in § 201.307(b)(3)(ii). (See comment 3 in section II of this document.)

VI. Analysis of Impacts

No comments were received in response to the agency's request for specific comment on the economic impact of this rulemaking (59 FR 15139 at 15141). FDA has examined the impacts of the final rule under Executive Order 12866 and the Regulatory Flexibility Act (5 U.S.C. 601–612). Executive Order 12866 directs agencies to assess all costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity). Under the Regulatory Flexibility Act, if a rule has a significant economic impact on a substantial number of small entities, an agency must analyze regulatory options that minimize any significant impact of the rule on small entities.

Title II of the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) requires that agencies prepare a written statement and economic analysis before proposing any rule that may result in an expenditure in any one year by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation). The proposed rule that has led to the development of this final rule was published on March 31, 1994, before the Unfunded Mandates Reform Act was enacted. The agency explains in this final rule that the final rule will not result in an expenditure in any 1 year by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million.

The agency believes that this final rule is consistent with the principles set out in the Executive Order and in these two statutes. The purpose of this final rule is to limit the OTC container size of one laxative drug product (sodium phosphates oral solution) to not more than 90 mL and to add warning and direction statements to the labeling of oral and rectal OTC sodium phosphates drug products. This container size limitation and the warning and direction statements concern product toxicity and are intended to help ensure the safe and effective use of all OTC sodium phosphates drug products. Potential benefits include reduced toxicity when consumers use these products.

The manufacturer of the only major trade product containing sodium phosphates oral solution marketed in a container size larger that 90 mL has already withdrawn that size product from the market. The agency is not able to identify any other sodium phosphates oral solution marketed by another manufacturer in a container exceeding 90 mL.

Regarding relabeling, the agency has been informed that relabeling costs of the type required by this final rule generally average about $2,000 to $3,000 per stock keeping unit (SKU) (individual products, packages, and sizes). The agency is aware of 3 manufacturers that together produce 4 SKU's of oral sodium phosphates drug products and approximately 125 SKU's of rectal sodium phosphates drug products. There may be a few additional small manufacturers or a few additional products in the marketplace that are not identified in the sources FDA reviewed. Assuming that there are about 130 affected OTC SKU's in the marketplace, total one-time costs of relabeling would be $260,000 to $390,000. The agency believes that actual cost could be lower for several reasons. First, most of the label changes will be made by private label manufacturers that tend to use simpler and less expensive labeling. Second, the agency is allowing supplementary labeling (e.g., stick-on labeling) to be used for those products not undergoing a new labeling printing within 120 days.

The final rule would not require any new reporting and recordkeeping activities. Therefore, no additional professional skills are needed. There are no other Federal rules that duplicate, overlap, or conflict with the final rule.

The agency considered but rejected several container size and labeling alternatives: (1) A container size limit of 45, 60, or 120 mL; (2) voluntary relabeling; (3) publication of the labeling information in the FDA Drug Bulletin or professional journals; and (4) an exemption from coverage for small entities. The alternate container sizes were not selected because 90 mL represents the upper limit of the two doses per container and physicians often prescribe this amount for bowel cleansing prior to surgery and diagnostic procedures of the colon. The agency does not consider voluntary relabeling or an exemption from coverage acceptable because they do not assure that consumers or health professionals will have the most recent needed information for safe and effective use of these sodium

phosphates drug products. The agency considers the third alternative useful and may proceed with such publications. However, such publications do not provide a permanent labeling requirement, which the agency considers necessary for these products.

This final rule may have a significant economic impact on the manufacturers of this product, all of which are considered small entities, using the U.S. Small Business Administration designations for this industry (750 employees). The agency believes that any other unidentified manufacturer of these products may also be a small entity. These manufacturers will need to change the information panel of each affected sodium phosphates SKU. Among the steps the agency is taking to minimize the impact on these small entities are: (1) To provide 120 days for implementation, as one comment requested, to enable entities to use up some existing labeling stock, and (2) to provide for the use of supplementary labeling (e.g., stick-on labeling) if necessary. The agency believes that these actions should help reduce the relabeling cost for small entities.

The agency considered a longer implementation period. The agency proposed a 30-day effective date, considered extending this to 60 days, and in response to public comment has extended the effective date to 120 days to reduce the economic burden on small entities. The agency considered but rejected a longer effective date because it would not assure that consumers have the most recent needed information for safe and effective use of OTC sodium phosphates drug products at the earliest possible time. The agency concludes that the overriding safety considerations warrant a 120-day implementation period.

The analysis shows that this final rule is not economically significant under Executive Order 12866 and that the agency has undertaken important steps to reduce the burden to small entities. Nevertheless, some entities, especially those private label manufacturers that provide labeling for a number of the affected products, may incur significant impacts. Thus, this economic analysis, together with other relevant sections of this document, serves as the agency's final regulatory flexibility analysis, as required under the Regulatory Flexibility Act. Finally, this analysis shows that the Unfunded Mandates Act does not apply to the final rule because it would not result in an expenditure in any one year by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million.

VII. Paperwork Reduction Act of 1995

FDA concludes that the labeling requirements in this document are not subject to review by the Office of Management and Budget because they do not constitute a ''collection of information'' under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). Rather, the labeling statements are a ''public disclosure of information orginally supplied by the Federal government to the recipient for the purpose of disclosure to the public'' (5 CFR 1320.3(c)(2)).

VIII. Environmental Impact

The agency has determined under 21 CFR 25.31(c) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

List of Subjects in 21 CFR Part 201

Drugs, Labeling, Reporting and recordkeeping requirements.

Therefore, under the Federal Food, Drug, and Cosmetic Act, and under authority delegated to the Commissioner of Food and Drugs, 21 CFR part 201 is amended as follows:

PART 201—LABELING

1. The authority citation for 21 CFR part 201 continues to read as follows:

Authority: 21 U.S.C. 321, 331, 351, 352, 353, 355, 356, 357, 358, 360, 360b, 360gg–360ss, 371, 374, 379e; 42 U.S.C. 216, 241, 262, 264.

2. Section 201.307 is added to subpart G to read as follows:

§ 201.307 Sodium phosphates; package size limitation, warnings, and directions for over-the-counter sale.

(a) Reports in the medical literature and data accumulated by the Food and Drug Administration indicate that multiple container sizes of sodium phosphates oral solution available in the marketplace have caused consumer confusion and appear to have been involved in several consumer deaths. Sodium phosphates oral solution has been marketed in 45-milliliter (mL), 90-mL, and 240-mL container sizes. The 45-mL and 90-mL container sizes of sodium phosphates oral solution are often recommended and prescribed by physicians for bowel cleansing prior to surgery and diagnostic procedures of the colon. Sodium phosphates oral solution (adult dose 20 mL to 45 mL) is also used as an over-the-counter (OTC) laxative for the relief of occasional constipation. Accidental overdosing and deaths have occurred because the 240-mL container was mistakenly used instead of the 45-mL or 90-mL container. The Food and Drug Administration is limiting the amount of sodium phosphates oral solution to not more than 90 mL (3 ounces (oz)) per OTC container because of the serious health risks associated with the ingestion of larger than intended doses of this product. Further, because an overdose of either oral or rectal enema sodium phosphates can cause an electrolyte imbalance, additional warning and direction statements are required for the safe use of any OTC laxative drug product containing sodium phosphates.

(b) Any OTC drug product for laxative or bowel cleansing use containing sodium phosphates as an active ingredient when marketed as described in paragraph (a) of this section is misbranded within the meaning of section 502 of the Federal Food, Drug, and Cosmetic Act unless packaged and labeled as follows:

(1) Package size limitation for sodium phosphates oral solution: Container shall not contain more than 90 mL (3 oz).

(2) Warnings. The following sentences shall appear in boldface type as the first statement under the heading ''Warnings.''

(i) Oral dosage forms. ''Taking more than the recommended dose in 24 hours can be harmful.''

(ii) Rectal enema dosage forms. ''Using more than one enema in 24 hours can be harmful.''

(3) Directions—(i) The labeling of all orally or rectally administered OTC drug products containing sodium phosphates shall contain the following directions in boldface type immediately preceding the dosage information: ''Do not'' (''take'' or ''use'') ''more unless directed by a doctor. See Warnings.''

(ii) For products containing dibasic sodium phosphate/monobasic sodium phosphate identified in § 334.16(d) marketed as a solution. Adults and children 12 years of age and over: Oral dosage is dibasic sodium phosphate 3.42 to 7.56 grams (g) and monobasic sodium phosphate 9.1 to 20.2 g (20 to 45 mL dibasic sodium phosphate/monobasic sodium phosphate oral solution) as a single daily dose. ''Do not take more than 45 mL (9 teaspoonfuls or 3 tablespoonfuls) in a 24-hour period.'' Children 10 and 11 years of age: Oral dosage is dibasic sodium phosphate 1.71 to 3.78 g and monobasic sodium phosphate 4.5 to 10.1 g (10 to 20 mL dibasic sodium phosphate/monobasic sodium phosphate oral solution) as a single daily dose. ''Do not take more than 20 mL (4 teaspoonfuls) in a 24-

hour period.'' Children 5 to 9 years of age: Oral dosage is dibasic sodium phosphate 0.86 to 1.89 g and monobasic sodium phosphate 2.2 to 5.05 g (5 to 10 mL dibasic sodium phosphate/ monobasic sodium phosphate oral solution) as a single daily dose. ''Do not take more than 10 mL (2 teaspoonfuls) in a 24-hour period.'' Children under 5 years of age: ask a doctor.

(c) After June 22, 1998, for package size limitation and September 18, 1998, for labeling in accord with paragraph (b) of this section, any such OTC drug product initially introduced or initially delivered for introduction into interstate commerce, or any such drug product that is repackaged or relabeled after these dates regardless of the date the product was manufactured, initially introduced, or initially delivered for introduction into interstate commerce, that is not in compliance with this section is subject to regulatory action.

Dated: April 28, 1998.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 98–12053 Filed 5–20–98; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 510

Animal Drugs, Feeds, and Related Products; Change of Sponsor Name

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect the change of sponsor name from Protiva, a unit of Monsanto, to Monsanto Co.

EFFECTIVE DATE: May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Thomas J. McKay, Center for Veterinary Medicine (HFV–102), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–827–0213.

SUPPLEMENTARY INFORMATION: Protiva, a unit of Monsanto has informed FDA of a change of sponsor name to Monsanto Co. Accordingly, FDA is amending 21 CFR 510.600(c)(1) and (c)(2) to reflect the change of sponsor name.

List of Subjects in 21 CFR Part 510

Administrative practice and procedure, Animal drugs, Labeling, Reporting and recordkeeping requirements.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR part 510 is amended as follows:

PART 510—NEW ANIMAL DRUGS

1. The authority citation for 21 CFR part 510 continues to read as follows:

Authority: 21 U.S.C. 321, 331, 351, 352, 353, 360b, 371, 379e.

§ 510.600 [Amended]

2. Section 510.600 *Names, addresses, and drug labeler codes of sponsors of approved applications* is amended in the table in paragraph (c)(1) by removing the entry for ''Protiva, A Unit of Monsanto Co.'' and by alphabetically adding a new entry for ''Monsanto Co., 800 North Lindbergh Blvd., St. Louis, MO 63167'' and in the table in paragraph (c)(2) in the entry for ''059945'' by removing the sponsor name ''Protiva, A Division of Monsanto Co.'' and adding in its place ''Monsanto Co.''

Dated: May 8, 1998.

Andrew J. Beaulieu,

Acting Director, Office of New Animal Drug Evaluation, Center for Veterinary Medicine.

[FR Doc. 98–13162 Filed 5–20–98; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Parts 510 and 558

Animal Drugs, Feeds, and Related Products; Change of Sponsor

AGENCY: Food and Drug Administration, HHS.

ACTION: Final rule.

SUMMARY: The Food and Drug Administration (FDA) is amending the animal drug regulations to reflect a change of sponsor for 96 new animal drug applications (NADA's) and 4 abbreviated animal drug applications (ANADA's) from Hoffmann-La Roche, Inc., to Roche Vitamins, Inc.

EFFECTIVE DATE: May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Thomas J. McKay, Center for Veterinary Medicine (HFV–102), Food and Drug Administration, 7500 Standish Pl., Rockville, MD 20855, 301–827–0213.

SUPPLEMENTARY INFORMATION: Hoffmann-La Roche, Inc., Nutley, NJ 07110, has informed FDA that it has transferred the ownership of and all rights and interests in approved NADA's and ANADA's to Roche Vitamins, Inc., 45 Waterview Blvd., Parsippany, NJ 07054–1298. Accordingly, the agency is amending the regulations in 21 CFR parts 510 and 558 to reflect the change of sponsor. The agency is also amending the regulations in § 510.600(c)(1) and (c)(2) by removing Hoffmann-La Roche, Inc., because the sponsor no longer sponsors any approved new animal drugs, and by alphabetically adding an entry for Roche Vitamins, Inc.

List of Subjects

21 CFR Part 510

Administrative practice and procedure, Animal drugs, Labeling, Reporting and recordkeeping requirements.

21 CFR Part 558

Animal drugs, Animal feeds.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs and redelegated to the Center for Veterinary Medicine, 21 CFR parts 510 and 558 are amended as follows:

PART 510—NEW ANIMAL DRUGS

1. The authority citation for 21 CFR part 510 continues to read as follows:

Authority: 21 U.S.C. 321, 331, 351, 352, 353, 360b, 371, 379e.

§ 510.600 Names, addresses, and drug labeler codes of sponsors of approved applications.

2. Section 510.600 is amended in the table in paragraph (c)(1) by removing the entry for ''Hoffmann-La Roche, Inc.,'' and by alphabetically adding an entry for ''Roche Vitamins, Inc.,'' and in the table in paragraph (c)(2) by removing the entry for ''000004'' and by numerically adding an entry for ''063238'' to read as follows:

§ 510.600 Names, addresses, and drug labeler codes of sponsors of approved applications.

* * * * *

(c) * * *

(1) * * *

Firm name and address	Drug labeler code
* * *	* * * *
Roche Vitamins, Inc., 45 Waterview Blvd., Parsippany, NJ 07054–1298	063238
* * *	* * * *

(2) * * *

Drug labeler code	Firm name and address
* * *	* * * *
063238	Roche Vitamins, Inc., 45 Waterview Blvd., Parsippany, NJ 07054–1298
* * *	* * * *

PART 558—NEW ANIMAL DRUGS FOR USE IN ANIMAL FEEDS

The authority citation for 21 CFR part 558 continues to read as follows:

Authority: 21 U.S.C. 360b, 371.

§ 558.58 [Amended]

3. Section 558.58 *Amprolium and ethopabate* is amended in the table in paragraph (d)(1)(iii), under the ''Limitations'' column in the entries for ''Bacitracin 4 to 50'', ''Bacitracin 5 to 35 plus roxarsone 34 (0.00375%)'', and ''Bacitracin 10 to 50 plus roxarsone 15.4 to 45.4 (0.0017% to 0.005%)'' by removing ''000004 and 046573'' and adding in its place ''046573 and 063238'', and under the ''Sponsor'' column by removing ''000004'' wherever it appears and adding in its place ''063238''.

§ 558.78 [Amended]

4. Section 558.78 *Bacitracin zinc* is amended in paragraph (a)(2), in the table in paragraph (d)(1), under the ''Sponsor'' column, and in paragraph (d)(2)(ii) by removing ''000004'' wherever it appears and adding in its place ''063238''.

§ 558.95 [Amended]

5. Section 558.95 *Bambermycins* is amended in paragraph (d)(1)(xi)(*b*) and (d)(1)(xii)(*b*) by removing ''Nos. 012799 and 000004'' and adding in its place ''Nos. 012799 and 063238''.

§ 558.120 [Amended]

6. Section 558.120 *Carbarsone (not U.S.P.)* is amended in paragraph (d)(1)(iii)(*b*) by removing ''Nos. 000004 and 046573'' and adding in its place ''Nos. 046573 and 063238''.

§ 558.128 [Amended]

7. Section 558.128 *Chlortetracycline* is amended in paragraph (a)(1) by removing ''000004'' and adding in its place ''063238'', and in the table in paragraph (d)(1), under the ''Sponsors'' column, by removing ''000004'' wherever it appears and adding in its place ''063238''.

§ 558.145 [Amended]

8. Section 558.145 *Chlortetracycline, procaine penicillin, and sulfamethazine* is amended in paragraph (a)(1) by removing ''000004 and 046573'' and adding in its place ''046573 and 063238'', and in paragraph (a)(2) by removing ''000004'' and adding in its place ''063238''.

§ 558.175 [Amended]

9. Section 558.175 *Clopidol* is amended in paragraph (d)(1)(iii)(*b*) and (d)(1)(iv)(*b*) by removing ''Nos. 000004 and 046573'' and adding in its place ''Nos. 046573 and 063238''.

§ 558.195 [Amended]

10. Section 558.195 *Decoquinate* is amended in the table in paragraph (d) in the entry for ''27.2 (0.003 pct.), Roxarsone 11 to 45 (0.0012–0.005 pct.) plus Bacitracin 12 to 50'' under the ''Limitations'' column by removing ''Nos. 000004, 011716, and 046573'' and adding in its place ''Nos. 011716, 046573, and 063238''.

§ 558.305 [Amended]

11. Section 558.305 *Laidlomycin propionate potassium* is amended in paragraph (a) by removing ''000004'' and adding in its place ''063238''.

§ 558.311 [Amended]

12. Section 558.311 *Lasalocid* is amended in paragraphs (b)(2), (b)(3), (b)(4), (b)(5), (b)(6), and (b)(7) by removing ''000004'' and adding in its place ''063238''; in the table in paragraph (e)(1)(v) under the ''Limitations''column by removing ''000004'' and adding in its place ''063238'' and under the ''Sponsors'' column by removing ''000007'' and adding in its place ''063238''; and in paragraphs (e)(2)(v) and (e)(3)(v) by removing ''000004'' and adding in its place ''063238''.

§ 558.340 [Amended]

13. Section 558.340 *Maduramicin ammonium* is amended in paragraph (a) by removing ''000004'' and adding in its place ''063238''.

§ 558.342 [Amended]

14. Section 558.342 *Melengestrol acetate* is amended in paragraph (d)(3)(ii) by removing ''000004'' and adding in its place ''063238'', and in paragraph (d)(6)(ii) by removing ''Nos. 000004, 000009, and 000986'', and adding in its place ''Nos. 000009, 000986, and 063238''.

§ 558.355 [Amended]

15. Section 558.355 *Monensin* is amended in paragraphs (b)(8), (b)(9), (f)(1)(iv)(*b*), (f)(1)(v)(*b*), (f)(1)(xiv)(*b*), (f)(1)(xv)(*b*) by removing ''000004'' and adding in its place ''063238'', and in paragraph (f)(1)(xvi)(*b*) by removing ''Nos. 000004 and 046573'' and adding in its place ''Nos. 046573 and 063238''.

§ 558.515 [Amended]

16. Section 558.515 *Robenidine hydrochloride* is amended in paragraphs (a) and (d)(1)(vi)(*b*) by removing ''000004'' and adding in its place ''063238''.

§ 558.550 [Amended]

17. Section 558.550 *Salinomycin* is amended in paragraphs (a)(1), (d)(1)(vii)(*c*), (d)(1)(xv)(*c*), and (d)(1)(xvi)(*c*) by removing ''000004'' and adding in its place ''063238'', and in paragraph (d)(1)(ix)(*c*) by removing ''Nos. 000004 and 046573'' and adding in its place ''Nos. 046573 and 063238''.

§ 558.575 [Amended]

18. Section 558.575 *Sulfadimethoxine, ormetoprim* is amended in paragraphs (a)(1) and (a)(2) by removing ''000004'' and adding in its place ''063238''.

§ 558.582 [Amended]

19. Section 558.582 *Sulfamerazine* is amended in paragraph (a) by removing ''000004'' and adding in its place ''063238''.

§ 558.600 [Amended]

20. Section 558.600 *Tiamulin* is amended in paragraph (c)(4)(ii) by removing ''000004 and 046573'' and adding in its place ''046573 and 063238''.

Dated: May 8, 1998.

Andrew J. Beaulieu,

Acting Director, Office of New Animal Drug Evaluation, Center for Veterinary Medicine.

[FR Doc. 98–13161 Filed 5–20–98; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF THE TREASURY

Office of Foreign Assets Control

31 CFR Part 537

Burmese Sanctions Regulations

AGENCY: Office of Foreign Assets Control, Treasury.

ACTION: Final rule.

SUMMARY: The Office of Foreign Assets Control of the U.S. Department of the Treasury is issuing the Burmese Sanctions Regulations to implement Executive Order 13047 of May 20, 1997, ''Prohibiting New Investment in Burma.''

EFFECTIVE DATE: May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Steven I. Pinter, Chief of Licensing, tel.: 202/622–2480, or William B. Hoffman, Chief Counsel, tel.: 202/622–2410, Office of Foreign Assets Control, Department of the Treasury, Washington, DC 20220.

SUPPLEMENTARY INFORMATION:

Electronic Availability

This document is available as an electronic file on *The Federal Bulletin Board* the day of publication in the **Federal Register**. By modem, dial 202/512–1387 and type ''/GO FAC,'' or call 202/512–1530 for disk or paper copies. This file is available for downloading without charge in WordPerfect 5.1, ASCII, and Adobe Acrobat[R] readable (*.PDF) formats. For Internet access, the address for use with the World Wide Web (Home Page), Telnet, or FTP protocol is: fedbbs.access.gpo.gov. The document is also accessible for downloading in ASCII format without charge from Treasury's Electronic Library (''TEL'') in the ''Business, Trade and Labor Mall'' of the FedWorld bulletin board. By modem, dial 703/321–3339, and select self–expanding file ''T11FR00.EXE'' in TEL. For Internet access, use one of the following protocols: Telnet = fedworld.gov (192.239.93.3); World Wide Web (Home Page) = http://www.fedworld.gov; FTP = ftp.fedworld.gov (192.239.92.205). Additional information concerning the programs of the Office of Foreign Assets Control is available for downloading from the Office's Internet Home Page: http://www.ustreas.gov/treasury/services/fac/fac.html, or in fax form through the Office's 24–hour fax–on–demand service: call 202/622–0077 using a fax machine, fax modem, or (within the United States) a touch–tone telephone.

Background

On May 20, 1997, the President issued Executive Order 13047 (the ''Order''), effective at 12:01 a.m. EDT on May 21, 1997, certifying to Congress under section 570(b) of the Foreign Operations, Export Financing, and Related Programs Appropriations Act, 1997, (Public Law 104–208) (the ''Act'') that the Government of Burma has committed large–scale repression of the Democratic opposition in Burma after September 30, 1996, thereby invoking the prohibition on new investment in Burma by U.S. persons, contained in that section. The President also declared a national emergency to deal with the threat posed to the national security and foreign policy of the United States by the actions and policies of the Government of Burma, invoking the authority, *inter alia*, of the International Emergency Economic Powers Act (50 U.S.C. 1701–1706). The Order authorizes the Secretary of the Treasury, in consultation with the Secretary of State, to take such actions, including the promulgation of rules and regulations, as may be necessary to carry out the purposes of the Order. In implementation of the Order, the Treasury Department is issuing the Burmese Sanctions Regulations, 31 CFR part 537 (the ''Regulations'').

Section 537.201 of the Regulations implements section 1 of the Order, and prohibits new investment in Burma by U.S. persons. The term *new investment*, defined in section 4(d) of the Order, means any of the following activities, if such an activity is undertaken pursuant to an agreement, or pursuant to the exercise of rights under such an agreement, that is entered into with the Government of Burma or a nongovernmental entity in Burma on or after May 21, 1997:

(1) the entry into a contract that includes the economic development of resources located in Burma;

(2) the entry into a contract providing for the general supervision and guarantee of another person's performance of a contract that includes the economic development of resources located in Burma;

(3) the purchase of a share of ownership, including an equity interest, in the economic development of resources located in Burma; or

(4) the entry into a contract providing for the participation in royalties, earnings, or profits in the economic development of resources located in Burma, without regard to the form of the participation.

Section 537.202 of the Regulations implements section 2(a) of the Order and prohibits any approval or other facilitation by a United States person, wherever located, of a transaction by a foreign person where the transaction would constitute prohibited new investment in Burma if engaged in by a United States person or within the United States.

Section 537.203 of the Regulations implements section 2(b) of the Order and prohibits any transaction by a U.S. person or within the United States that evades or avoids, or that has the purpose of evading or avoiding, or attempts to violate, any of the prohibitions set forth in the Order.

The prohibitions contained in these sections are subject to the exemption contained in section 3 of the Order, implemented in § 537.204 of the Regulations, which excludes from the new investment and facilitation prohibitions the entry into or performance or financing of a contract to sell or purchase goods, services, or technology. This exemption, however, does not apply where the entry into such a contract on or after the effective date of the Order is for the general supervision and guarantee of another person's performance of a contract for the economic development of resources located in Burma; or where such

contract provides for payment, in whole or in part, in: (1) shares of ownership, including an equity interest, in the economic development of resources located in Burma; or (2) participation in royalties, earnings or profits in the economic development of resources located in Burma. Section 537.301 indicates that the term *economic development of resources located in Burma* shall not be construed to include not–for–profit educational, health, or other humanitarian programs or activities. See § 537.301.

Transactions otherwise prohibited under § 537.201 may not be authorized unless the President, or the President's duly authorized designee, exercises waiver authority provided in section 570(e) of the Act, upon a determination and certification to Congress that application of the waived sanction would be contrary to the national security interests of the United States. Transactions otherwise prohibited under §§ 537.202 and 537.203 but found to be consistent with U.S. policy may be authorized by a general license contained in subpart E of this part or by a specific license issued pursuant to the procedures described in subpart C of 31 CFR part 501. Civil and criminal penalties for violation of the Regulations are described in subpart G.

Since the Regulations involve a foreign affairs function, the provisions of Executive Order 12866 and the Administrative Procedure Act (5 U.S.C. 553)(the ''APA'') requiring notice of proposed rulemaking, opportunity for public participation, and delay in effective date are inapplicable. Because no notice of proposed rulemaking is required for this rule, the Regulatory Flexibility Act (5 U.S.C. 601–612) does not apply.

Paperwork Reduction Act

As authorized in the APA, the Regulations are being issued without prior notice and public comment procedure. The collections of information related to the Regulations are contained in 31 CFR part 501 (the ''Reporting and Procedures Regulations''). Pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3507), those collections of information have been approved by the Office of Management and Budget (''OMB'') under control number 1505–0164. An adjustment to the approved burden hours to reflect the additional burden imposed in administering the Regulations has been filed with OMB. 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 control number.

List of Subjects in 31 CFR Part 537

Administrative practice and procedure, Burma, Penalties, New investment, Reporting and recordkeeping requirements.

For the reasons set forth in the preamble, 31 CFR part 537 is added to read as follows:

PART 537—BURMESE SANCTIONS REGULATIONS

Subpart A—Relation of this Part to Other Laws and Regulations

Sec.

537.101 Relation of this part to other laws and regulations.

Subpart B—Prohibitions

537.201 Prohibited new investment by U.S. persons.
537.202 Prohibited approval or other facilitation by a U.S. person of a foreign person's investment.
537.203 Evasions; attempts; conspiracies.
537.204 Exempt transactions.

Subpart C—General Definitions

537.301 Economic development of resources located in Burma.
537.302 Effective date.
537.303 Entity.
537.304 Foreign person.
537.305 General license.
537.306 Government of Burma.
537.307 License.
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537.309 Nongovernmental entity in Burma.
537.310 Person.
537.311 Resources located in Burma.
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537.313 United States.
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Subpart D—Interpretations

537.401 Reference to amended sections.
537.402 Effect of amendment.
537.403 Economic development of resources located in Burma.
537.404 Purchase of shares in economic development projects in Burma.
537.405 Investment in entities involved in economic development projects in Burma.
537.406 General supervision and guarantee.
537.407 Activities under pre–May 21, 1997 agreements.
537.408 Sale or purchase of goods, services or technology.
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Subpart E—Licenses, Authorizations and Statements of Licensing Policy

537.501 General and specific licensing procedures.
537.502 Effect of license or authorization.
537.503 Exclusion from licenses and authorizations.
537.504 Divestiture of U.S. person's equity investment in Burma.

Subpart F—Reports

537.601 Recordkeeping and reporting requirements.

Subpart G—Penalties

537.701 Penalties.
537.702 Prepenalty notice.
537.703 Response to prepenalty notice; informal settlement.
537.704 Penalty imposition or withdrawal.
537.705 Administrative collection action; referral to United States Department of Justice.

Subpart H—Procedures

537.801 Procedures.
537.802 Delegation by the Secretary of the Treasury.

Subpart I—Paperwork Reduction Act

537.901 Paperwork Reduction Act notice.

Authority: 3 U.S.C. 301; 31 U.S.C. 321(b); 50 U.S.C. 1601–1651, 1701–1706; sec 570, Pub. L. 104–208, 110 stat. 3009–166; E.O. 13047, 61 FR 28301, 3 CFR, Comp., p. 202.

Subpart A—Relation of This Part to Other Laws and Regulations

§ 537.101 Relation of this part to other laws and regulations.

(a) This part is separate from, and independent of, the other parts of this chapter. Differing foreign policy and national security contexts may result in differing interpretations of similar language among the parts of this chapter. No license or authorization contained in or issued pursuant to those other parts authorizes any transaction prohibited by this part.

(b) No license or authorization contained in or issued pursuant to this part relieves the involved parties from complying with any other applicable laws or regulations.

Subpart B—Prohibitions

§ 537.201 Prohibited new investment by U.S. persons.

Except to the extent provided in regulations, orders, directives, or licenses that may by issued in conformity with section 570 of the Foreign Operations, Export Financing, and Related Programs Appropriations Act, 1997 (Public Law 104–208)(the ''Act''), new investment in Burma by United States persons is prohibited.

Note to § 537.201: Section 570 of the Act provides that the prohibition contained in this section may be waived, temporarily or permanently, by the President if he determines and certifies to Congress that the application of this sanction would be contrary to the national interests of the United States. Licenses are thus not available for purposes of authorizing transactions prohibited under this section in the absence

of such a waiver determination and certification to Congress.

§ 537.202 Prohibited approval or other facilitation by a U.S. person of a foreign person's investment.

Except to the extent provided in regulations, orders, directives, or licenses that may be issued pursuant to this part, any approval or other facilitation by a United States person, wherever located, of a transaction by a foreign person where the transaction would constitute prohibited new investment in Burma under this part if engaged in by a United States person or within the United States is prohibited.

§ 537.203 Evasions; attempts; conspiracies.

Except to the extent provided in regulations, orders, directives, or licenses that may be issued pursuant to this part, any transaction by a United States person or within the United States that evades or avoids, or has the purpose of evading or avoiding, or attempts to violate, any of the prohibitions set forth in this part is prohibited.

§ 537.204 Exempt transactions.

Nothing in this part shall be construed to prohibit the entry into, performance of, or financing of a contract to sell or purchase goods, services, or technology, except:

(a) Where the entry into such a contract on or after the effective date is for the general supervision and guarantee of another person's performance of a contract for the economic development of resources located in Burma; or

(b) Where such contract provides for payment, in whole or in part, in:

(1) Shares of ownership, including an equity interest, in the economic development of resources located in Burma; or

(2) Participation in royalties, earnings, or profits in the economic development of resources located in Burma.

Note to § 537.204: The term *economic development of resources located in Burma* is defined in § 537.301 to exclude not–for–profit educational, health or other humanitarian programs or activities.

Subpart C—General Definitions

§ 537.301 Economic development of resources located in Burma.

The term *economic development of resources located in Burma* shall not be construed to include not–for–profit educational, health, or other humanitarian programs or activities.

§ 537.302 Effective date.

The term *effective date* refers to the effective date of the applicable prohibitions and directives contained in this part which is 12:01 a.m. EDT, May 21, 1997.

§ 537.303 Entity.

The term *entity* means a partnership, association, trust, joint venture, corporation, or other organization.

§ 537.304 Foreign person.

The term *foreign person* means any citizen or national of a foreign state or any entity not organized under the laws of the United States.

§ 537.305 General license.

The term *general license* means any license or authorization the terms of which are set forth in this part.

§ 537.306 Government of Burma.

The term *Government of Burma* includes:

(a) The state and the Government of Burma, as well as any political subdivision, agency, or instrumentality thereof;

(b) Any entity owned or controlled directly or indirectly by the foregoing.

§ 537.307 License.

Except as otherwise specified, the term *license* means any license or authorization contained in this part, or issued pursuant to the authority of this part under procedures set forth in this part or in subpart C of part 501 of this chapter.

§ 537.308 New investment.

The term *new investment* means any of the following activities, if such an activity is undertaken pursuant to an agreement, or pursuant to the exercise of rights under such an agreement, that is entered into with the Government of Burma or a nongovernmental entity in Burma on or after the effective date:

(a) The entry into a contract that includes the economic development of resources located in Burma;

(b) The entry into a contract providing for the general supervision and guarantee of another person's performance of a contract that includes the economic development of resources located in Burma;

(c) The purchase of a share of ownership, including an equity interest, in the economic development of resources located in Burma; or

(d) The entry into a contract providing for the participation in royalties, earnings, or profits in the economic development of resources located in Burma, without regard to the form of the participation.

§ 537.309 Nongovernmental entity in Burma.

The term *nongovernmental entity in Burma* means a partnership, association, trust, joint venture, corporation, or other organization, wheresoever organized, that is located in Burma or exists for the exclusive or predominant purpose of engaging in the economic development of resources located in Burma or derives its income predominantly from such economic development, and is not the Government of Burma.

§ 537.310 Person.

The term *person* means an individual or entity.

§ 537.311 Resources located in Burma.

The term *resources located in Burma* means any resources, including natural, agricultural, commercial, financial, industrial and human resources, located within the territory of Burma, including the territorial sea, or located within the exclusive economic zone or continental shelf of Burma.

§ 537.312 Specific license.

The term *specific license* means any license or authorization not set forth in this part but issued pursuant to the authority of this part.

§ 537.313 United States.

The term *United States* means the United States, its territories and possessions, and all areas under the jurisdiction or authority thereof.

§ 537.314 United States person; U.S. person.

The term *United States person* or *U.S. person* means any United States citizen, permanent resident alien, juridical person organized under the laws of the United States (including foreign branches), or any person in the United States.

Subpart D—Interpretations

§ 537.401 Reference to amended sections.

Except as otherwise specified, reference to any section of this part or to any regulation, ruling, order, instruction, direction, or license issued pursuant to this part shall be deemed to refer to the same as currently amended.

§ 537.402 Effect of amendment.

Any amendment, modification, or revocation of any section of this part or of any order, regulation, ruling, instruction, or license issued by or under the direction of the Director of the Office of Foreign Assets Control shall not, unless otherwise specifically provided, be deemed to affect any act done or omitted to be done, or any civil

or criminal suit or proceeding commenced or pending prior to such amendment, modification, or revocation. All penalties, forfeitures, and liabilities under any such order, regulation, ruling, instruction, or license shall continue and may be enforced as if such amendment, modification, or revocation had not been made.

§ 537.403 Economic development of resources located in Burma.

The term *economic development of resources located in Burma* refers to activities pursuant to a contract the subject of which includes responsibility for the development or exploitation of resources located in Burma, including making or attempting to make those resources accessible or available for exploitation or economic use. Examples include contracts conferring rights to explore for, develop, extract, or refine petroleum, natural gas, or minerals in the ground in Burma; contracts to take over a mining operation in Burma; acquire a forest or agricultural area and exploit the timber or other crops; or acquire land and construct and run a hotel or factory on it. The term *economic development of resources located in Burma* is defined in § 537.301 specifically to exclude contracts for not–for–profit educational, health or other humanitarian programs or activities. See also § 537.204 for the exception that applies to the entry into, performance of, or financing of a contract to sell or purchase goods, services or technology.

§ 537.404 Purchase of shares in economic development projects in Burma.

The purchase of shares, including an equity interest, in the economic development of resources located in Burma, is prohibited when those shares are purchased after the effective date directly or indirectly from the Government of Burma or a nongovernmental entity in Burma, unless purchased pursuant to an agreement entered into prior to May 21, 1997. U.S. persons may purchase debt instruments issued by the Government of Burma or a nongovernmental entity in Burma, directly or indirectly, provided that such instruments are not convertible into equity, and do not provide for participation, including as collateral or security, in royalties, earnings, or profits in the economic development of resources located in Burma.

§537.405 Investments in entities involved in economic development projects in Burma.

(a) The purchase of shares in a third–country company that is engaged in the economic development of resources located in Burma is prohibited by § 537.201 where the company's profits are predominantly derived from the company's economic development of resources located in Burma.

(b) If a U.S. person holds shares in an entity which subsequently engages exclusively or predominantly in the economic development of resources located in Burma or subsequently derives its income exclusively or predominantly from such economic development, the United States person is not required to relinquish its shares, but may not purchase additional shares. Divestment of the shares in such an entity to a foreign person — constituting the facilitation of that foreign person's investment in Burma — is authorized under general license pursuant to § 537.504.

§537.406 General supervision and guarantee.

Section 537.201 prohibits the entry by a U.S. person into a contract providing for the general supervision and guarantee of another person's performance of a contract that includes the economic development of resources located in Burma, if the U.S. person's contract is entered into on or after the effective date, unless undertaken pursuant to, or in exercise of rights under, a pre–effective date agreement. For the purposes of § 537.201, only the entry into contracts for supervision and guarantee at the top level of project management, such as entry into a contract with a development project's sponsor or owner to become a prime contractor or general manager for a development project, will be considered new investment in Burma. By contrast, subcontracts to provide goods, services, or technology to a prime contractor or general manager of a development project are exempt from the prohibitions of this part pursuant to § 537.204 unless:

(a) The functional scope of the subcontractor's obligations is substantially similar to that of a prime contractor's or general manager's obligations; or

(b) The consideration for such subcontracts includes a share of ownership in, or participation in the royalties, earnings or profits of, the economic development of resources located in Burma.

§ 537.407 Activities under pre–May 21, 1997 agreements.

(a) Activities undertaken by a U.S. person pursuant to an agreement entered into prior to May 21, 1997, between the U.S. person and the Government of Burma or a nongovernmental entity in Burma are not prohibited new investments, as defined in § 537.308.

(b) A U.S. person who is a party to a pre–effective date agreement for the development of economic resources located in Burma may enter into subsequent agreements with foreign persons where such agreements are pursuant to, or in exercise of rights under, the pre–effective date agreement. The facilitation of foreign persons' investment in Burma under these circumstances is authorized pursuant to the general license contained in § 537.504.

(c) A U.S. person may not enter into a contract for the economic development of resources located in Burma after May 21, 1997, if pursuant to, or in exercise of rights under, a pre–effective date agreement, unless the contractual arrangement is specifically contemplated in the pre–effective date agreement.

(d) The exercise of rights under pre–effective date agreements may include the exercise of options to extend the contract, depending on such factors as the degree of specificity with which the option to extend is described in the pre–effective date agreement, and the degree to which the party wishing to renew can enforce its decision to exercise the option.

§ 537.408 Sale or purchase of goods, services or technology.

(a) Section 537.204 exempts from any prohibition under this part the entry into, performance of, or financing of a contract to sell or purchase goods, services, or technology, except:

(1) Where the entry into a contract on or after the effective date is for the general supervision and guarantee of another person's performance of a contract for the economic development of resources located in Burma; or

(2) Where such contract provides for payment, in whole or in part, in:

(i) Shares of ownership, including an equity interest, in the economic development of resources located in Burma; or

(ii) Participation in royalties, earnings, or profits in the economic development of resources located in Burma.

(b) *Examples:* The following examples are based upon the assumption that neither § 537.204(a) nor § 537.204(b) applies.

(1) A U.S. person may market goods or services in Burma through a sales representative or sales agent, or through a U.S. person or subsidiary established and operating in Burma before May 21, 1997, or through any established foreign (including Burmese) distributorship.

The U.S. person may not, however, establish and operate a new business, branch, office or showroom in Burma to market such goods or services or facilitate the establishment of a new foreign entity to do so. This would constitute the development of a commercial resource.

(2) A U.S. person may rent, lease or purchase space in existing buildings in connection with the continued operation of a business in operation prior to the effective date. It may change locations, modify and renovate existing space and upgrade machinery or equipment. Unless pursuant to a pre–effective date agreement or the exercise of specific rights under such agreement, however, the U.S. person may not expand its business operations by opening additional stores, branches, offices or showrooms beyond the number that were in existence immediately prior to May 21, 1997. The U.S. person may not construct a new commercial building to house its business as this would constitute the economic development of land and commercial resources in Burma.

(3) A U.S. person involved in exempt activities may hire and train Burmese employees to carry out such activities. The employment of personnel in Burma under these circumstances is considered the purchase of employment services which is exempt from prohibition under § 537.204. Any training incidental to the performance of the employee's services is likewise exempt. For example, a U.S. person engaged in the sale of copy machines may hire and train a Burmese employee to carry out activities pursuant to such sales, including office support personnel, personnel to provide after–sale service and maintenance in accordance with the terms of a purchase or lease agreement, sales representatives and supervisory personnel. A U.S. person may not, however, open a business after the effective date, the purpose of which is the sale of vocational skills training in the maintenance of copy machines, as this would constitute the economic development of human resources in Burma.

(4) Contracts for the purchase or sale of services incident to the registration and renewal of patents, trademarks and copyrights are not prohibited by this part.

(5) A U.S. bank is allowed to provide trade financing as a service either to the Government of Burma or to nongovernmental entities in Burma, but cannot provide them loans earmarked for economic development of resources in Burma if loan repayment is secured by the project. A U.S. bank can provide development project financing as a service, so long as the financing instruments are not convertible into equity, and do not provide for participation, including as collateral or security, in royalties, earnings, or profits in the economic development of resources located in Burma.

§ 537.409 Approval or other facilitation of a foreign person's investment.

(a) The prohibition contained in § 537.202 against approval or other facilitation of a foreign person's investment in Burma bars any action by a U.S. person that assists or supports a foreign person's activity that would constitute prohibited new investment under § 537.201 if engaged in by a U.S. person. This facilitation prohibition is subject to the exemption for trade in goods, services and technology set forth in § 537.204.

(b) *Examples:* (1) A U.S. corporation is prohibited from brokering, financing, guaranteeing, or approving the entry by any foreign person, including a foreign affiliate, into a contract for the development of, e.g., a natural gas field, a tourist hotel complex, or a rubber plantation in Burma, unless pursuant to the affiliate's exercise of rights under an agreement entered into prior to the effective date. An independent U.S. contractor, however, may perform brokerage, financing, or guarantee services if under a service contract meeting the conditions of § 537.204.

(2) The sale to a foreign person of a U.S. person's equity or income interest in a development project in Burma constitutes facilitation of that foreign person's investment in Burma, unless pursuant to a pre–effective date agreement. Such a sale, however, is authorized by general license under § 537.504.

(3) A U.S. national or permanent resident alien employed in Burma or in a third country by a foreign person may participate in any decision–making role in an activity by the foreign person that includes economic development of resources located in Burma as exempt employment services pursuant to § 537.204, unless such services are undertaken pursuant to a post–effective date agreement between the foreign person and the Government of Burma or a nongovernmental entity in Burma and:

(i) involve the general supervision and guarantee of the foreign person's performance of a contract for the economic development of resources located in Burma, or

(ii) where the individual U.S. person's compensation is provided for, in whole or in part, from shares of ownership in the development project or participation in royalties, earnings, or profits in the development project.

Subpart E—Licenses, Authorizations, and Statements of Licensing Policy

§ 537.501 General and specific licensing procedures.

For provisions relating to licensing procedures, see subpart C of part 501 of this chapter.

§ 537.502 Effect of license or authorization.

(a) No license or other authorization contained in this part, or otherwise issued by or under the direction of the Director of the Office of Foreign Assets Control, shall be deemed to authorize or validate any transaction effected prior to the issuance of the license, unless specifically provided in such license or authorization.

(b) No regulation, ruling, instruction, or license authorizes any transaction prohibited under this part unless the regulation, ruling, instruction, or license is issued by the Office of Foreign Assets Control and specifically refers to this part. No regulation, ruling, instruction, or license referring to this part shall be deemed to authorize any transaction prohibited by any provision of this chapter unless the regulation, ruling, instruction or license specifically refers to such provision.

(c) Any regulation, ruling, instruction, or license authorizing any transaction otherwise prohibited under this part has the effect of removing a prohibition or prohibitions contained in this part from the transaction, but only to the extent specifically stated by its terms. Unless the regulation, ruling, instruction, or license otherwise specifies, such an authorization does not create any right, duty, obligation, claim, or interest in, or with respect to, any property which would not otherwise exist under ordinary principles of law.

§ 537.503 Exclusion from licenses and authorizations.

The Director of the Office of Foreign Assets Control reserves the right to exclude any person, property, or transaction from the operation of any license, or from the privileges therein conferred, or to restrict the applicability thereof with respect to particular persons, property, transactions, or classes thereof. Such action shall be binding upon all persons receiving actual or constructive notice of such exclusion or restriction.

§ 537.504 Divestiture of U.S. person's equity investment in Burma.

Notwithstanding the prohibition in § 537.202 against the facilitation by a

U.S. person of a foreign person's investment, all transactions related to the divestiture or transfer to a foreign person of a U.S. person's share of ownership including an equity interest in the economic development of resources located in Burma are authorized. U.S. persons participating in such transactions valued at more than $10,000 are required, within 10 business days after the agreement is signed, to file a report for statistical purposes with the Office of Foreign Assets Control, U.S. Treasury Department, 1500 Pennsylvania Avenue NW—Annex, Washington, DC 20220.

Note to § 537.504: This authorization includes arrangements by U.S. persons with pre–effective date investments in Burma to ''farm in'' or sell a stake in the investment to a foreign person. For purposes of this section, the term *farm–in arrangement* is defined to mean the sale of an equity interest in an investment in the economic development of resources located in Burma.

Subpart F—Reports

§ 537.601 Recordkeeping and reporting requirements.

For provisions relating to records and reports, see subpart B of part 501 of this chapter.

Subpart G—Penalties

§ 537.701 Penalties.

(a) Attention is directed to section 206 of the International Emergency Economic Powers Act (50 U.S.C. 1705) (the ''Act''), which is applicable to violations of the provisions of any license, ruling, regulation, order, direction or instruction issued by or pursuant to the direction or authorization of the Secretary of the Treasury pursuant to this part or otherwise under the Act. Section 206 of the Act, as adjusted by the Federal Civil Penalties Inflation Adjustment Act of 1990 (Pub.L. 101–410, as amended, 28 U.S.C. 2461 note), provides that:

(1) A civil penalty of not to exceed $11,000 per violation may be imposed on any person who violates any license, order, or regulation issued under the Act;

(2) Whoever willfully violates any license, order, or regulation issued under the Act shall, upon conviction, be fined not more than $50,000, or, if a natural person, may be imprisoned for not more than 10 years, or both; and any officer, director, or agent of any corporation who knowingly participates in such violation may be punished by a like fine, imprisonment or both.

(b) The criminal penalties provided in the Act are subject to increase pursuant to 18 U.S.C. 3571.

(c) Attention is also directed to 18 U.S.C. 1001, which provides that whoever, in any matter within the jurisdiction of any department or agency of the United States, knowingly and willfully falsifies, conceals or covers up by any trick, scheme, or device a material fact, or makes any false, fictitious or fraudulent statements or representations or makes or uses any false writing or document knowing the same to contain any false, fictitious or fraudulent statement or entry, shall be fined under title 18, United States Code, or imprisoned not more than 5 years, or both.

(d) Violations of this part may also be subject to relevant provisions of other applicable laws.

§ 537.702 Prepenalty notice.

(a) *When required.* If the Director of the Office of Foreign Assets Control has reasonable cause to believe that there has occurred a violation of any provision of this part or a violation of the provisions of any license, ruling, regulation, order, direction or instruction issued by or pursuant to the direction or authorization of the Secretary of the Treasury pursuant to this part or otherwise under the International Emergency Economic Powers Act, and the Director determines that further proceedings are warranted, he shall issue to the person concerned a notice of his intent to impose a monetary penalty. The prepenalty notice shall be issued whether or not another agency has taken any action with respect to this matter.

(b) *Contents*—(1) *Facts of violation.* The prepenalty notice shall describe the violation, specify the laws and regulations allegedly violated, and state the amount of the proposed monetary penalty.

(2) *Right to respond.* The prepenalty notice also shall inform the respondent of respondent's right to make a written presentation within 30 days of mailing of the notice as to why a monetary penalty should not be imposed, or, if imposed, why it should be in a lesser amount than proposed.

§ 537.703 Response to prepenalty notice; informal settlement.

(a) *Deadline for response.* The respondent shall have 30 days from the date of mailing of the prepenalty notice to make a written response to the Director of the Office of Foreign Assets Control.

(b) *Form and contents of response.* The written response need not be in any particular form, but shall contain information sufficient to indicate that it is in response to the prepenalty notice. It should contain responses to the allegations in the prepenalty notice and set forth the reasons why the respondent believes the penalty should not be imposed or, if imposed, why it should be in a lesser amount than proposed.

(c) *Informal settlement.* In addition or as an alternative to a written response to a prepenalty notice pursuant to this section, the respondent or respondent's representative may contact the Office of Foreign Assets Control as advised in the prepenalty notice to propose the settlement of allegations contained in the prepenalty notice and related matters. In the event of settlement at the prepenalty stage, the claim proposed in the prepenalty notice will be withdrawn, the respondent is not required to take a written position on allegations contained in the prepenalty notice, and the Office of Foreign Assets Control will make no final determination as to whether a violation occurred. The amount accepted in settlement of allegations in a prepenalty notice may vary from the civil penalty that might finally be imposed in the event of a formal determination of violation. In the event no settlement is reached, the 30–day period specified in paragraph (a) of this section for written response to the prepenalty notice remains in effect unless additional time is granted by the Office of Foreign Assets Control.

§ 537.704 Penalty imposition or withdrawal.

(a) *No violation.* If, after considering any response to the prepenalty notice and any relevant facts, the Director of the Office of Foreign Assets Control determines that there was no violation by the respondent named in the prepenalty notice, the Director promptly shall notify the respondent in writing of that determination and that no monetary penalty will be imposed.

(b) *Violation.* If, after considering any response to the prepenalty notice, the Director of the Office of Foreign Assets Control determines that there was a violation by the respondent named in the prepenalty notice, the Director promptly shall issue a written notice of the imposition of the monetary penalty to the respondent.

(1) The penalty notice shall inform the respondent that payment of the assessed penalty must be made within 30 days of the mailing of the penalty notice.

(2) The penalty notice shall inform the respondent of the requirement to furnish the respondent's taxpayer identification number pursuant to 31 U.S.C. 7701 and that such number will be used for purposes of collection and

reporting on any delinquent penalty amount in the event of a failure to pay the penalty imposed.

§ 537.705 Administrative collection; referral to United States Department of Justice.

In the event that the respondent does not pay the penalty imposed pursuant to this part or make payment arrangements acceptable to the Director of the Office of Foreign Assets Control within 30 days of the mailing of the written notice of the imposition of the penalty, the matter may be referred for administrative collection measures by the Department of the Treasury or to the United States Department of Justice for appropriate action to recover the penalty in a civil suit in a Federal district court.

Subpart H—Procedures

§ 537.801 Procedures.

For provisions relating to procedures, see subpart C of part 501 of this chapter.

§ 537.802 Delegation by the Secretary of the Treasury.

Any action which the Secretary of the Treasury is authorized to take pursuant to Executive Order 13047 or any further executive orders relating to the national emergency declared in Executive Order 13047 may be taken by the Director of the Office of Foreign Assets Control, or by any other person to whom the Secretary of the Treasury has delegated authority so to act.

Subpart I—Paperwork Reduction Act

§ 537.901 Paperwork Reduction Act notice.

For approval by the Office of Management and Budget under the Paperwork Reduction Act of information collections relating to recordkeeping and reporting requirements, to licensing procedures pursuant to statements of licensing policy, and to other procedures, see § 501.901 of this chapter.

Dated: April 21, 1998.

R. Richard Newcomb,

Director, Office of Foreign Assets Control.

Approved: May 11, 1998.

James E. Johnson,

Assistant Secretary (Enforcement), Department of the Treasury.

[FR Doc. 98–13477 Filed 5–18–98; 9:52 am]

BILLING CODE 4810–25–F

DEPARTMENT OF TRANSPORTATION

Coast Guard

33 CFR Part 165

[CGD01–98–041]

RIN 2121–AA97

Safety Zone; Fleet Week Air/Sea Demonstrations, Hudson River, NY

AGENCY: Coast Guard, DOT.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a temporary safety zone in the Hudson River, rectangular in shape, perpendicular to the USS INTREPID, for air/sea demonstrations. The safety zone is in effect from 10:30 a.m. until 12:30 p.m. on May 22, 23, and 24, and from 2:30 p.m. until 4:30 p.m. on May 22, 23, 24 and 25, 1998. This action is necessary to provide for the safety of life on navigable waters in the event of aircraft problems developing during the demonstrations. It is intended to restrict vessel traffic in the Hudson River.

DATES: This rule is effective from 10:30 a.m. until 12:30 p.m. on May 22, 23, and 24, and from 2:30 p.m. until 4:30 p.m. on May 22, 23, 24 and 25, 1998.

ADDRESSES: Comments may be mailed to Commander (wob) (CGD01–98–041), Coast Guard Activities New York, 212 Coast Guard Drive, Staten Island, New York 10305–5005, or deliver them to room 205 at the same address between 8 a.m. and 3 p.m., Monday through Friday, except federal holidays.

The Waterways Oversight Branch of Coast Guard Activities New York maintains the public docket for this rulemaking. Comments, and documents as indicated in this preamble, will become part of this docket and will be available for inspection or copying in room 205 at the same address between 8 a.m. and 3 p.m., Monday through Friday, except federal holidays.

FOR FURTHER INFORMATION CONTACT: Lieutenant (Junior Grade) A. Kenneally, Waterways Oversight Branch, Coast Guard Activities New York, at (718) 354–4195.

SUPPLEMENTARY INFORMATION:

Regulatory History

Pursuant to 5 U.S.C. 553, a notice of proposed rulemaking (NPRM) was not published for this regulation. Good cause exists for not publishing an NPRM and for making this regulation effective less than 30 days after **Federal Register** publication. Due to the date that conclusive information for these events was received, there was insufficient time to draft and publish an NPRM. Any delay encountered in this regulation's effective date would be contrary to public interest since immediate action is needed to close a portion of the waterway and protect the maritime public from the hazards associated with these air/sea demonstrations, which are intended for public entertainment.

Background and Purpose

The U.S. Marine Corps, Navy, and Coast Guard hold joint air/sea demonstrations in and over the Hudson River in the vicinity of the USS INTREPID Museum as a part of Fleet Week festivities. This regulation establishes a safety zone which includes those waters of the Hudson River bound by the following points: from the southeast corner of Pier 90, Manhattan, where it intersects the seawall, outbound to a position at 40°46′10″N latitude, 074°00′13″W longitude (NAD 1983), south to a point at 40°45′54″N, 074°00′24″W (NAD 1983), then inbound to the northeast corner of Pier 83 where it intersects the seawall. The safety zone is in effect from 10:30 a.m. until 12:30 p.m. on May 22, 23, and 24, and from 2:30 p.m. until 4:30 p.m. on May 22, 23, 24 and 25, 1998. The safety zone prevents vessels from transiting this portion of the Hudson River and is needed to protect commercial and recreational traffic from the hazards associated with the turbulence generated by vertical take-off aircraft. Vessels moored at piers within the safety zone may remain moored for the duration of the safety zone; however, they will not be allowed to transit from their moorings without permission from the Captain of the Port, New York, during the effective periods of the safety zone.

Regulatory Evaluation

This final rule is not a significant regulatory action under section 3(f) of Executive Order 12866 and does not require an assessment of potential costs and benefits under section 6(a)(3) of that Order. It has not been reviewed by the Office of Management and Budget under that Order. It is not significant under the regulatory policies and procedures of the Department of Transportation (DOT) (44 FR 11040; February 26, 1979). The Coast Guard expects the economic impact of this final rule to be so minimal that a full Regulatory Evaluation under paragraph 10e of the regulatory policies and procedures of DOT is unnecessary. This finding is based on the following: commercial and recreational vessels navigating the Hudson River can alter their route west of the affected area, commercial ferries will be allowed to transit to and from

their berths at Pier 83, Manhattan during the demonstration at the discretion of the Captain of the Port, and the extensive, advance notifications which will be made.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), the Coast Guard considered whether this rule will have a significant economic impact on a substantial number of small entities. ''Small entities'' include 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.

For the reasons discussed in the Regulatory Evaluation section above, the Coast Guard certified under section 605(b) of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) that this rule will not have a significant economic impact on a substantial number of small entities.

Collection of Information

This final rule does not provide for a collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

Federalism

The Coast Guard has analyzed this final rule under the principles and criteria contained in Executive Order 12612, and has determined that this final rule does not have sufficient implications for federalism to warrant the preparation of a Federalism Assessment.

Environment

The Coast Guard considered the environmental impact of this rule and concluded that under Figure 2–1, paragraph 34(g), of Commandant Instruction M16475.1C, this final rule is categorically excluded from further environmental documentation. A ''Categorical Exclusion Determination'' is available in the docket for inspection or copying where indicated under **ADDRESSES**.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

Regulation

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR Part 165 as follows:

PART 165—[AMENDED]

1. The authority citation for Part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 50 U.S.C. 191; 33 CFR 1.05–1(g), 6.04–1, 6.04–6, and 160.5; 49 CFR 1.46.

2. Add temporary section 165.T01–041 to read as follows:

§ 165.T01–041 Safety Zone; Fleet Week Air/Sea Demonstrations, Hudson River, New York.

(a) *Location.* The following area is a safety zone: those waters of the Hudson River bound by the following points: from the southeast corner of Pier 90, Manhattan, where it intersects the seawall, outbound to a position at 40°46′10″ N latitude, 074°100′13″ W longitude (NAD 1983), south to a point at or near 40°45′54″ N latitude, 074°00′24″ W longitude (NAD 1983), then inbound to the northeast corner of Pier 83, Manhattan, where it intersects the seawall.

(b) *Effective period.* This section is in effect from 10:30 a.m. until 12:30 p.m. on May 22, 23, and 24, and from 2:30 p.m. until 4:30 p.m. on May 22, 23, 24 and 25, 1998.

(c) *Regulations.*

(1) The general regulations contained in 33 CFR 165.23 apply.

(2) All persons and vessels shall comply with the instructions of the Coast Guard Captain of the Port or the designated on scene patrol personnel. U.S. Coast Guard patrol personnel include commissioned, warrant, and petty officers of the Coast Guard. Upon being hailed by a U.S. Coast Guard vessel via siren, radio, flashing light, or other means, the operator of a vessel shall proceed as directed.

Dated: April 15, 1998.

Richard C. Vlaun,

Captain, U.S. Coast Guard Captain of the Port, New York.

[FR Doc. 98–13580 Filed 5–18–98; 4:49 pm]

BILLING CODE 4910–15–M

DEPARTMENT OF VETERANS AFFAIRS

38 CFR Part 21

RIN 2900–AJ10

Veterans Education: Increase in Rates Payable for Cooperative Training Under the Montgomery GI Bill—Active Duty

AGENCY: Department of Veterans Affairs.

ACTION: Final rule.

SUMMARY: This document amends the educational assistance and educational benefits regulations of the Department of Veterans Affairs (VA). The Veterans' Benefits Act of 1997 provided a new statutory formula for use in calculating the monthly rates of educational assistance payable under the Montgomery GI Bill—Active Duty to someone pursuing cooperative training. The new formula increases the monthly rates of educational assistance, effective from October 9, 1996, for veterans in cooperative training who were formerly eligible for assistance under the Veteran Era GI Bill. This final document amends the regulations to reflect the increased rates.

DATES: Effective Date: October 9, 1996

FOR FURTHER INFORMATION CONTACT: William G. Susling, Jr., Education Advisor, Education Service, Veterans Benefits Administration, (202) 273–7187.

SUPPLEMENTARY INFORMATION: VA is amending the ''ALL VOLUNTEER FORCE EDUCATIONAL ASSISTANCE PROGRAM (MONTGOMERY GI BILL—ACTIVE DUTY)'' regulations set forth at 38 CFR Part 21, Subpart K. VA is required by statute to calculate the monthly rate of educational assistance payable to veterans and servicemembers training under the Montgomery GI Bill—Active Duty (MGIB). The calculation is based on statutory formulas.

Effective October 9, 1996, Pub. L. 105–114 changed the statutory formula used to determine the monthly rate of educational assistance under the MGIB payable to a veteran in cooperative training who was formerly eligible for assistance under the Vietnam Era GI Bill. This final rule revises the regulations containing the monthly rate of educational assistance payable to such a veteran to reflect the new statutory formula.

The changes set forth in this final rule are applied from the effective date of the statutory changes.

This final rule merely reflects statutory requirements and adjustments made based on the newly established formula. Accordingly, there is a basis for dispensing with prior notice and comment and delayed effective date provisions of 5 U.S.C. 552 and 553.

The Secretary of Veterans Affairs hereby certifies that this final rule will not have a significant economic impact on a substantial number of small entities as they are defined in the Regulatory Flexibility Act, 5 U.S.C. 601–612 and does not directly affect small entities. This final rule directly affects only individuals. Pursuant to 5 U.S.C. 605(b), this final rule, therefore, is exempt from the initial and final regulatory flexibility

analyses requirements of sections 603 and 604.

The Catalog of Federal Domestic Assistance number for the program affected by this final rule is 64.124.

List of Subjects in 38 CFR Part 21

Administrative practice and procedure, Armed forces, Civil rights, Claims, Colleges and universities, Conflict of interests, Defense Department, Education, Employment, Grant programs-education, Grant programs-veterans, Health programs, Loan programs-education, Loan programs-veterans, Manpower training programs, Reporting and recordkeeping requirements, Schools, Travel and transportation expenses, Veterans, Vocational education, Vocational rehabilitation.

Approved: May 12. 1998.

Togo D. West, Jr.,

Secretary.

For the reasons set out above, 38 CFR part 21, subpart K, is amended as set forth below.

PART 21—VOCATIONAL REHABILITATION AND EDUCATION

Subpart K—All Volunteer Force Educational Assistance Program (Montgomery GI Bill—Active Duty)

1. The authority citation for part 21, subpart K continues to read as follows:

Authority: 38 U.S.C. 501(a), chs. 30, 39, unless otherwise noted.

2. In § 21.7137, paragraph (a)(3) is revised to read as follows:

§ 21.7137 Rates of payment of basic educational assistance for individuals with remaining entitlement under 38 U.S.C. ch. 34.

(a) * * *

(3) The monthly rate payable to a veteran who is pursuing a cooperative course is the rate stated in the following table:

Training period	Monthly rate			
	No dependents	One dependent	Two dependents	Additional for each additional dependent
Oct. 9, 1996–Sept. 30, 1997	$615.87	$651.37	$682.87	$16.00
On or after Oct. 1, 1997	627.85	663.85	694.85	16.00

(Authority: 38 U.S.C. 3015)

* * * * * * *

[FR Doc. 98–13526 Filed 5–20–98; 8:45 am]

BILLING CODE 8320–01–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 61

[FRL–5990–4]

Delegation of New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) for the State of Nevada

AGENCY: Environmental Protection Agency (EPA).

ACTION: Delegation of authority.

SUMMARY: In 1990, 1991 and 1993, the State of Nevada, Department of Conservation and Natural Resources (NDCNR), requested delegation of authority for the implementation and enforcement of specified New Source Performance Standards (NSPS) and the National Emission Standards for Hazardous Air Pollutants (NESHAPS). EPA's review of the State of Nevada's laws, rules and regulations showed them to be adequate for the implementation and enforcement of these federal standards, and EPA granted the delegations as requested.

EFFECTIVE DATE: The effective dates of the delegation authority for the NDCNR agency are: September 10, 1992, February 24, 1993, and September 23, 1993.

ADDRESSES: Copies of the requests for delegation of authority and EPA's letters of delegation are available for public inspection at EPA's Region 9 office during normal business hours and at the following location: State of Nevada, Department of Conservation and Natural Resources, 333 W. Nye Lane, Carson City, NV 89710.

FOR FURTHER INFORMATION CONTACT: Cynthia G. Allen, Rulemaking Section (Air-4), Air Division, EPA, Region 9, 75 Hawthorne Street, San Francisco, CA 94105–3901, Tel: (415) 744–1189.

SUPPLEMENTARY INFORMATION: Section 301, in conjunction with sections 110, 111(c)(1), and 112(l)(1) of the Clean Air Act as amended in 1990, authorize the Administrator to delegate his or her authority to implement and enforce the standards set out in 40 CFR part 60, Standards of Performance for New Stationary Sources (NSPS) and 40 CFR part 61, National Emission Standards for Hazardous Air Pollutants (NESHAPS).

The State of Nevada requested authority for delegation of certain NSPS and NESHAPS categories. After a thorough review of the categories requested for delegation, the Regional Administrator, EPA Region IX determined that such delegation was appropriate for these source categories. By letters dated September 10, 1992, February 24, 1993, and September 23, 1993, EPA delegated its authority for 40 CFR part 60 and part 61 for the following subparts:

NSPS	40 CFR part 60, subpart
Industrial-Commercial-Institutional Steam Generating Units.	Db
Small Industrial-Commercial-Institutional Steam Generating Units.	Dc
Municipal Waste Combustors	Ea
Petroleum Refineries	J
Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry.	DDD
VOC Emissions from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) Air Oxidation Unit Processes.	III
VOC Emissions from SOCMI Distillation Operations.	NNN
Calciners and Dryers in Mineral Industries.	UUU

NESHAPS	40 CFR part 61, subpart
Benzene Emissions from Benzene Transfer Operations.	BB
Benzene Waste Operations	FF

Under the terms of the delegations, NDCNR is required to follow all applicable provisions of 40 CFR parts 60 and 61, including but not limited to use of EPA's test methods and continuous monitoring procedures.

As of the effective dates of the delegations, NDCNR has primary authority to enforce the standards listed above. EPA retains independent enforcement authority, and will exercise such authority in a manner consistent with EPA's ''Timely and Appropriate Enforcement Response to Significant Air Pollution Violators'' Guidance, and any revisions thereto, and applicable enforcement agreements.

As of the effective dates of the delegations, all notifications and reports required of sources by the above standards should be sent to NDCNR with a copy to EPA Region IX.

The EPA hereby notifies the public that it has delegated the authority over the above-listed NSPS and NESHAPS subparts to the State of Nevada, Department of Conservation and Natural Resources.

The Office of Management and Budget has exempted this action from Executive Order 12866 review.

This notice is issued under the authority of sections 101, 110, 111, 112, and 301 of the Clean Air Act, as amended (42 U.S.C. sections 7401, 7410, 74121, 7412, and 7601).

Dated: March 23, 1998.

Felicia Marcus,

Regional Administrator, Region IX.

[FR Doc. 98–13617 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 300

[FRL–6015–6]

National Oil and Hazardous Substances Contingency Plan; National Priorities List Update

AGENCY: Environmental Protection Agency.

ACTION: Notice of deletion of the National Lead Industries/Taracorp/Golden Auto Parts Superfund site from the National Priorities List (NPL).

SUMMARY: The Environmental Protection Agency (EPA) announces the deletion of the National Lead Industries/Taracorp/Golden Auto Parts Site in Minnesota from the National Priorities List (NPL). The NPL is Appendix B of 40 CFR part 300 which is the National Oil and Hazardous Substances Contingency Plan (NCP), which EPA promulgated pursuant to section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), as amended. This action is being taken by EPA and the State of Minnesota, because it has been determined that Responsible Parties have implemented all appropriate response actions required. Moreover, EPA and the State of Minnesota have determined that remedial actions conducted at the site to date remain protective of public health, welfare, and the environment.

EFFECTIVE DATE: May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Lawrence Schmitt at (312) 353–6565 (SR–6J), Remedial Section Chief or Gladys Beard at (312) 886–7253, Associate Remedial Project Manager, Superfund Division, U.S. EPA—Region V, 77 West Jackson Blvd., Chicago, IL 60604. Information on the site is available at the local information repository located at: St. Louis Park Library, 3240 Library Lane, St. Louis Park, MN 55417 and St. Louis Park City, 5005 Minnetonka, St. Louis Park, MN 55416. Requests for comprehensive copies of documents should be directed formally to the Regional Docket Office. The contact for the Regional Docket Office is Jan Pfundheller (H–7J), U.S. EPA, Region V, 77 W. Jackson Blvd., Chicago, IL 60604, (312) 353–5821.

SUPPLEMENTARY INFORMATION: The site to be deleted from the NPL is: National Lead Industries/Taracorp/Golden Auto Parts Site located in St. Louis Park, Minnesota. A Notice of Intent to Delete for this site was published April 3, 1998 (63 FR 16465). The closing date for comments on the Notice of Intent to Delete was May 4, 1998. EPA received no comments and therefore no Responsiveness Summary was prepared.

The EPA identifies sites which appear to present a significant risk to public health, welfare, or the environment and it maintains the NPL as the list of those sites. Sites on the NPL may be the subject of Hazardous Substance Response Trust Fund (Fund-) financed remedial actions. Any site deleted from the NPL remains eligible for Fund-financed remedial actions in the unlikely event that conditions at the site warrant such action. Section 300.425(e)(3) of the NCP states that Fund-financed actions may be taken at sites deleted from the NPL in the unlikely event that conditions at the site warrant such action. Deletion of a site from the NPL does not affect responsible party liability or impede agency efforts to recover costs associated with response efforts.

List of Subjects in 40 CFR Part 300

Environmental protection, Air pollution control, Chemicals, Hazardous substances, Hazardous waste, Intergovernmental relations, Penalties, Reporting and recordkeeping requirements, Superfund, Water pollution control, Water supply.

Dated: May 8, 1998.

Michelle D. Jordan,

Acting Regional Administrator, Region V.

For the reasons set out in the preamble, 40 CFR part 300 is amended as follows:

PART 300—[AMENDED]

1. The authority citation for Part 300 continues to read as follows:

Authority: 33 U.S.C. 1321(c)(2); 42 U.S.C. 9601–9657; E.O. 12777, 56 FR 54757, 3 CFR, 1991 Comp.; p. 351; E.O. 12580, 52 FR 2923, 3 CFR, 1987 Comp.; p. 193.

Appendix B [Amended]

2. Table 1 of Appendix B to part 300 is amended by removing the site ''NL Industries/Taracorp/Golden Auto, St. Louis Park''.

[FR Doc. 98–13441 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 300

[FRL–6015–7]

National Oil and Hazardous Substances Contingency Plan; National Priorities List Update

AGENCY: Environmental Protection Agency.

ACTION: Notice of deletion of the H & K Sales Superfund site from the National Priorities List (NPL).

SUMMARY: The Environmental Protection Agency (EPA) announces the deletion of the H & K Sales site in Michigan from the National Priorities List (NPL). The NPL is Appendix B of 40 CFR part 300 which is the National Oil and Hazardous Substances Contingency Plan (NCP), which EPA promulgated pursuant to section 105 of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA), as amended. This action is being taken by EPA and the State of Michigan, because it has been determined that Responsible Parties have implemented all appropriate response actions required. Moreover, EPA and the State of Michigan have determined that

remedial actions conducted at the site to date remain protective of public health, welfare, and the environment.

EFFECTIVE DATE: May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Kevin Adler at (312) 886–7078 (SR–6J), Remedial Project Manager or Gladys Beard at (312) 886–7253, Associate Remedial Project Manager, Superfund Division, U.S. EPA—Region V, 77 West Jackson Blvd., Chicago, IL 60604. Information on the site is available at the local information repository located at: The Alvah N. Belding Library, 302 East Main Street, Belding, Michigan 48809. Requests for comprehensive copies of documents should be directed formally to the Regional Docket Office. The contact for the Regional Docket Office is Jan Pfundheller (H–7J), U.S. EPA, Region V, 77 W. Jackson Blvd., Chicago, IL 60604, (312) 353–5821.

SUPPLEMENTARY INFORMATION: The site to be deleted from the NPL is: H & K Sales Site located in Belding, Michigan. A Notice of Intent to Delete for this site was published March 30, 1998 (63 FR 15125). The closing date for comments on the Notice of Intent to Delete was April 29, 1998. EPA received no comments and therefore no Responsiveness Summary was prepared.

The EPA identifies sites which appear to present a significant risk to public health, welfare, or the environment and it maintains the NPL as the list of those sites. Sites on the NPL may be the subject of Hazardous Substance Response Trust Fund (Fund-) financed remedial actions. Any site deleted from the NPL remains eligible for Fund-financed remedial actions in the unlikely event that conditions at the site warrant such action. Section 300.425(e)(3) of the NCP states that Fund-financed actions may be taken at sites deleted from the NPL in the unlikely event that conditions at the site warrant such action. Deletion of a site from the NPL does not affect responsible party liability or impede agency efforts to recover costs associated with response efforts.

List of Subjects in 40 CFR Part 300

Environmental protection, Air pollution control, Chemicals, Hazardous substances, Hazardous waste, Intergovernmental relations, Penalties, Reporting and recordkeeping requirements, Superfund, Water pollution control, Water supply.

Dated: May 8, 1998.

Michelle D. Jordan,

Acting Regional Administrator, Region V.

For the reasons set out in the preamble, 40 CFR part 300 is amended as follows:

PART 300—[AMENDED]

1. The authority citation for Part 300 continues to read as follows:

Authority: 33 U.S.C. 1321(c)(2); 42 U.S.C. 9601–9657; E.O. 12777, 56 FR 54757, 3 CFR, 1991 Comp.; p. 351; E.O. 12580, 52 FR 2923, 3 CFR, 1987 Comp.; p. 193.

Appendix B [Amended]

2. Table 1 of Appendix B to part 300 is amended by removing the site ''H & K Sales, Belding.''

[FR Doc. 98–13440 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL EMERGENCY MANAGEMENT AGENCY

44 CFR Part 65

RIN 3067–AC81

National Flood Insurance Program; Removal of Form

AGENCY: Federal Emergency Management Agency (FEMA).

ACTION: Final rule.

SUMMARY: This rule removes appendix A to part 65, which contains the FEMA Standard Flood Hazard Determination form, and removes reference to the form and tells readers how to obtain copies of it. The form is used in the process of making, increasing, extending, renewing, selling, or transferring mortgages to ensure that buildings and mobile homes located in an identified Special Flood Hazard Area (SFHA) are covered by flood insurance. FEMA will publish notices of the availability of the form from time to time; the form is also available by fax-on-demand and on the Internet at FEMA's web site. Removal of the form from the CFR will enhance FEMA's ability to incorporate changes to the form outside of the rulemaking process, while continuing to provide full notice of availability of the form to the public and to affected parties.

EFFECTIVE DATE: This rule is effective on May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Matthew B. Miller, P.E., Mitigation Directorate, Federal Emergency Management Agency, 500 C Street SW., Washington, DC 20472, (202) 646–3461, or by facsimile at (202) 646–4596 (not toll-free calls) for additional information.

SUPPLEMENTARY INFORMATION. As part of our implementation of the National Flood Insurance Reform Act of 1994, FEMA published a final rule at 60 FR 35276, July 6, 1995, to establish a standard form for determining whether a building or mobile home is located in an SFHA, whether flood insurance is required, and whether Federal flood insurance is available. The federal entities for lending regulation published a final rule (60 FR 35286, July 6, 1995) requiring use of the form. Use of the form by federally regulated lenders became mandatory on January 2, 1996. The OMB number for the current form expires on April 30, 1998 but OMB has extended the expiration date for an additional 90 days.

During the two years that this form has been in use, many users have commented on the form asking FEMA to make minor changes and clarifications. By separate notice published today in the **Federal Register** we propose changes to the form and we request comments on the proposed changes from the public and from other Federal agencies.

This rule removes Appendix A to Part 65—Federal Emergency Management Agency, Standard Flood Hazard Determination Form and Instructions. The form will continue in use and will continue to be available by written request, by fax-on-demand, and through the Internet at http://www.fema.gov/nfip/mpurfi.htm. Removal of the form from the Code of Federal Regulations will enhance FEMA's ability to incorporate changes to the form outside of the rulemaking process, while continuing to provide full notice of the availability of the form to the public and to affected parties.

This rule also revises 44 CFR 65.16, Standard Flood Hazard Determination Form and instructions. The revision removes the reference to the form and instructions being found in Appendix A to Part 65 and tells how readers can obtain copies of the form and its accompanying instructions.

Executive Order 12866, Regulatory Planning and Review

This final rule is not a significant regulatory action within the meaning of § 2(f) of E.O. 12866 of September 30, 1993, 58 FR 51735, but attempts to adhere to the regulatory principles set forth in E.O. 12866. The rule has not been reviewed by the Office of Management and Budget under E.O. 12866.

Regulatory Flexibility Act.

The Director certifies that this rule is not a major rule under Executive Order 12291. It will not have significant impact on a substantial number of small entities within the meaning of the Regulatory Flexibility Act, and is not expected (1) to affect adversely the availability of disaster assistance

funding to small entities, (2) to have significant secondary or incidental effects on a substantial number of small entities, or (3) to create any additional burden on small entities. FEMA has not prepared a regulatory flexibility analysis of this proposed rule.

Paperwork Reduction Act

This final rule does not contain a collection of information and therefore is not subject to the provisions of the Paperwork Reduction Act of 1995.

Congressional Review of Agency Rulemaking

This final rule has been submitted to the Congress and to the General Accounting Office under the Congressional Review of Agency Rulemaking Act, Pub. L. 104–121. The rule is not a ''major rule'' within the meaning of that Act. It is an administrative action in support of normal day-to-day activities. It does not result in nor is it likely to result in an annual effect on the economy of $100,000,000 or more; it will not result in a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions; and it will not have ''significant adverse effects'' on competition, employment, investment, productivity, innovation, or on the ability of United States-based enterprises to compete with foreign-based enterprises.

This final rule is exempt (1) from the requirements of the Regulatory Flexibility Act, and (2) from the Paperwork Reduction Act. The rule is not an unfunded Federal mandate within the meaning of the Unfunded Mandates Reform Act of 1995, Pub.L. 104–4. It does not meet the $100,000,000 threshold of that Act, and any enforceable duties are imposed as a condition of Federal assistance or a duty arising from participation in a voluntary Federal program.

List of Subjects in 44 CFR Part 65

Flood insurance, Reporting and recordkeeping requirements.

Accordingly, 44 CFR Part 65 is amended as follows:

PART 65—IDENTIFICATION AND MAPPING OF SPECIAL HAZARD AREAS

1. The authority citation for Part 65 continues to read as follows:

Authority: 42 U.S.C. 4001 *et seq.*; Reorganization Plan No. 3 of 1978, 43 FR 41943, 3 CFR, 1978 Comp., p. 329; E.O. 12127 of March 31, 1979, 44 FR 19367, 3 CFR, 1979 Comp, p. 376.

Appendix A to Part 65 [Removed]

2. Appendix A to Part 65—Federal Emergency Management Agency, Standard Flood Hazard Determination Form and Instructions is removed.

3. Section 65.16 is revised to read as follows:

§ 65.16 Standard Flood Hazard Determination Form and Instructions.

(a) Section 528 of the National Flood Insurance Reform Act of 1994 (42 U.S.C. 1365(a)) directs FEMA to develop a standard form for determining, in the case of a loan secured by improved real estate or a mobile home, whether the building or mobile home is located in an area identified by the Director as an area having special flood hazards and in which flood insurance under this title is available. The purpose of the form is to determine whether a building or mobile home is located within an identified Special Flood Hazard Area (SFHA), whether flood insurance is required, and whether federal flood insurance is available. Use of this form will ensure that required flood insurance coverage is purchased for structures located in an SFHA, and will assist federal entities for lending regulation in assuring compliance with these purchase requirements.

(b) The form is available by written request to Federal Emergency Management Agency, PO Box 2012, Jessup, MD 20794; ask for the Standard Flood Hazard Determination form. It is also available by fax-on-demand; call (202) 646–3362, form # 23103. Finally, the form is available through the Internet at http://www.fema.gov/nfip/mpurfi.htm.

Dated: May 14, 1998.

James L. Witt,

Director.

[FR Doc. 98–13443 Filed 5–20–98; 8:45 am]

BILLING CODE 6718–04–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 54

[CC Docket Nos. 97–21, 96–45, DA 98–158]

Universal Service; Correction

AGENCY: Federal Communications Commission.

ACTION: Correcting amendments.

SUMMARY: This document contains corrections to final regulations that were published in the **Federal Register** of August 1, 1997, (62 FR 41304). The regulations related to the administration of the Commission's federal universal service support mechanism.

DATES: Effective on May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Sheryl Todd, Common Carrier Bureau, (202) 418–7400.

SUPPLEMENTARY INFORMATION:

Background

On January 29, 1998, the Commission released errata to the Report and Order and Second Order on Reconsideration, DA 98–158, in CC Dockets 97–21 and 96–45. This correction reflects the changes included in that errata. The full text of the errata is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M St., NW, Washington, DC.

Need for Correction

As published, the final regulations contain an incorrect cross-reference.

List of Subjects in 47 CFR Part 54

Health facilities, Libraries, Reporting and recordkeeping requirements, Schools, Telecommunications, Telephone.

Accordingly, 47 CFR part 54 is corrected by making the following correcting amendments:

PART 54—UNIVERSAL SERVICE

1. The authority citation for part 54 continues to read as follows:

Authority: 47 U.S.C. 151, 154(i), 201, 205, 214 and 254.

§ 54.507 Cap [Corrected]

2. In § 54.507, paragraph (g)(4), in the first sentence, remove the reference to ''(f)(2) and (f)(3)'' and add, in its place ''(g)(2) and (g)(3).''

Federal Communications Commission.

Lisa Gelb,

Chief, Accounting Policy Division.

[FR Doc. 98–13238 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 97–185; RM–9080, RM–9197]

Radio Broadcasting Services; Vergennes, VT, Willsboro and Malone, NY

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: The Commission, at the request of Watertown Radio Associates, reallots Channel 244A from Vergennes,

Vermont, to Willsboro, New York, and modifies Station WXPS(FM)'s license accordingly. *See* 62 FR 45784, August 29, 1997. In response to a counterproposal filed by Cartier Communications, the Commission substitutes Channel 243C3 for Channel 243A at Malone, New York, and modifies the license of Station WVNV(FM) to reflect the higher powered channel. Both channels can be allotted in compliance with the Commission's minimum distance separation requirements. Channel 244A can be allotted to Willsboro with a site restriction of 5.2 kilometers (3.2 miles) southeast at coordinates 44–19–20 NL and 73–21–00 WL. Channel 243C3 can be allotted with a site restriction of 16.0 kilometers (10.0 miles) northeast at coordinates 44–54–40 NL and 74–06–40 WL. Since both allotments create short-spacing conflicts to Canadian stations, we have obtained Canadian approval for Channel 244A at Willsboro and Channel 243C3 at Malone as specially negotiated short-spaced allotments. With this action, this proceeding is terminated.

EFFECTIVE DATE: June 29, 1998.

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

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Report and Order, MM Docket No. 97–185, adopted May 6, 1998, and released May 15, 1998. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, NW, Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, ITS, Inc., (202) 857–3800, 1231 20th Street, NW, Washington, DC 20036.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

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

PART 73—[AMENDED]

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

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

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under Vermont, is amended by removing Channel 244A at Vergennes.

3. Section 73.202(b), the Table of FM Allotments under New York, is amended by removing Channel 243A and adding Channel 243C3 at Malone; by adding Willsboro, Channel 244A.

Federal Communications Commission.

John A. Karousos,

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

[FR Doc. 98–13566 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 98–12; 9220]

Radio Broadcasting Services; Speculator, NY

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: The Commission, at the request of Michael Celenza and Peter Hunn, allots Channel 243A to Speculator, NY, as the community's first local FM service. *See* 63 FR 7360, February 13, 1998. Channel 243A can be allotted to Speculator in compliance with the Commission's minimum distance separation requirements without the imposition of a site restriction, at coordinates 43–29–50 North Latitude; 74–21–44 West Longitude. Canadian concurrence in the allotment has been received since Speculator is located within 320 kilometers (200 miles) of the U.S.-Canadian border. With this action, this proceeding is terminated.

DATES: Effective June 29, 1998. A filing window for Channel 243A at Speculator, NY, will not be opened at this time. Instead, the issue of opening a filing window for this channel will be addressed by the Commission in a subsequent order.

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

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Report and Order, MM Docket No. 98–12, adopted May 6, 1998, and released May 15, 1998. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, International Transcription Services, Inc., (202) 857–3800, 1231 20th Street, NW, Washington, DC 20036.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

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

PART 73—[AMENDED]

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

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

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under New York, is amended by adding Speculator, Channel 243A.

Federal Communications Commission.

John A. Karousos,

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

[FR Doc. 98–13565 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 98–23; RM–9226]

Radio Broadcasting Services; Eureka, Montana

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: This document allots Channel *240C3 to Bozeman, Montana, and reserves the channel for noncommercial educational use in response to a petition filed by Bozeman Educational Access Radio. *See* 63 FR 11401, March 9, 1998. The coordinates for Channel *240C3 at Bozeman are 45–40–48 and 111–02–18. With this action, this proceeding is terminated.

EFFECTIVE DATE: June 29, 1998.

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

SUPPLEMENTARY INFORMATION: This is a summary of the Commission's Report and Order, MM Docket No. 98–23, adopted May 6, 1998, and released May 15, 1998. The full text of this Commission decision is available for inspection and copying during normal business hours in the Commission's Reference Center (Room 239), 1919 M Street, NW, Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractors, International Transcription Services, Inc., 1231 20th Street, NW., Washington, DC. 20036, (202) 857–3800, facsimile (202) 857–3805.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

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

47 CFR PART 73—[AMENDED]

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 Montana, is amended by adding Channel *240C3 at Bozeman.

Federal Communications Commission.

John A. Karousos,

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

[FR Doc. 98–13564 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 98–15; RM–9142]

Radio Broadcasting Services; Brinkley and Colt, AR

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: This document reallots Channel 272C2 from Brinkley to Colt, Arkansas, and modifies the authorization of East Arkansas Broadcasters, Inc. for Station KQMC-FM to specify operation on Channel 272C2 at Colt, Arkansas, as requested, pursuant to the provisions of Section 1.420(i) of the Commission's Rules. *See* 63 FR 7361, Feburary 13, 1998. The allotment of Channel 272C2 to Colt will provide that community with its first local aural transmission facility without depriving Brinkley of local aural service. Coordinates used for Channel 272C2 at Colt are 34–58–10 NL and 90–51–07 WL. With this action, the proceeding is terminated.

EFFECTIVE DATE: June 29, 1998.

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

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Report and Order, MM Docket No. 98–15, adopted May 6, 1998, and released May 15, 1998. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC's Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, International Transcription Service, Inc., 1231 20th Street, NW., Washington, DC 20036, (202) 857–3800.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

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

PART 73—[AMENDED]

1. The authority citation for part 73 reads as follows:

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

§ 73.202 [Amended]

2. Section 73.202(b), the Table of FM Allotments under Arkansas, is amended by removing Channel 272C2 at Brinkley and adding Colt, Channel 272C2.

Federal Communications Commission.

John A. Karousos,

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

[FR Doc. 98–13563 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

48 CFR Parts 1842 and 1853

Revision to the NASA FAR Supplement on Contractor Performance Information

AGENCY: National Aeronautics and Space Administration (NASA).

ACTION: Interim rule.

SUMMARY: This is an interim rule amending the NASA FAR Supplement (NFS) to implement FAR requirement to evaluate contractor performance. Since the changes either conform NASA procedures to those of the FAR, implement FASA-related FAR changes, or affect acquisition procedures to the extent that immediate adoption is necessary, NASA is issuing the changes as an interim rule, with an effective date 60 days after publication.

DATES: This rule is effective July 20, 1998. All comments on this interim rule should be in writing and must be received by July 20, 1998.

ADDRESSES: Paul Brundage, Code HK, NASA Headquarters, 300 E Street, SW, Washington, DC 20456–0001.

FOR FURTHER INFORMATION CONTACT: Paul Brundage, (202) 358–0481.

SUPPLEMENTARY INFORMATION:

Background

FAR 42.15 requires that Federal agencies evaluate contract performance for each contract in excess of $100,000. NASA is amending the NFS to provide specific internal procedures for accomplishing this evaluation.

Impact

NASA certifies that this regulation will not have a significant economic impact on a substantial number of small business entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). This interim rule does not impose any reporting or recordkeeping requirements subject to the Paperwork Reduction Act.

Lists of Subjects in 48 CFR Parts 1842 and 1853

Government procurement.

Deidre Lee,

Associate Administrator for Procurement.

Accordingly, 48 CFR Parts 1842 and 1853 are amended as follows:

1. The authority citation for 48 CFR Parts 1842 and 1853 continues to read as follows:

Authority: 42 U.S.C. 2473(c)(1).

PART 1842—CONTRACT ADMINISTRATION

Subpart 1842.15 [Added]

2. Subpart 1842.15 is added to read as follows:

Subpart 1842.15—Contractor Performance Information

Sec.
1842.1501 General.
1842.1502 Policy.
1842.1503 Procedures.

1842.1501 General.

Communications with contractors are vital to improved performance and this is NASA's primary objective in evaluating past performance. Other objectives include providing data for both future source selections and for reports under NASA's Contractor Performance Assessment Program (CPAP). While the evaluations must reflect both shortcomings and achievements during performance, they should also elicit from the contractors their views on impediments to improved performance emanating from the Government or other sources.

1842.1502 Policy. (NASA Supplement paragraph (a))

(a) Within 60 days of every anniversary of the award of a contract having a term exceeding one year, contracting officers shall conduct interim evaluations of performance on

contracts subject to FAR subpart 42.15 and this subpart. The final evaluation shall cover only the last period of performance (i.e., it shall not be cumulative).

1842.1503 Procedures. (NASA Supplement paragraphs (a), (b), and (c))

(a) The contracting officer shall determine who (e.g., the technical office or end users of the products or services) evaluates appropriate portions of the contractor's performance. The evaluations are subjective in nature. Nonetheless, the contracting officer, who has responsibility for the evaluations, shall ensure that they are reasonable.

(b) NASA Form 1680, entitled, ''Evaluation of Performance,'' shall be used to document evaluations. This provides for a five-tiered rating (using the definitions for award fee evaluation scoring found in 1816.405–275) covering the following attributes: quality, timeliness, price or control of costs (not required for firm-fixed-price contracts or firm-fixed-price contracts with economic price adjustment), and other considerations. Evaluations used in determining award fee payments satisfy the requirements of this subpart and do not require completion of NASA Form 1680. In addition, hybrid contracts containing both award fee and non-award fee portions do not require completion of NASA Form 1680.

(c) Contracting Officers shall ensure that the Government discusses all evaluations with contractors and shall record the date and the participants on the evaluation form. Contracting officers shall sign and date the evaluation after considering any comments received from the contractor within 30 days of the contractor's receipt of the evaluation. If a contractor in its timely comments disagrees with an evaluation and requests a review at a level above the contracting officer, it shall be provided within 30 days. While the FAR forbids use of the evaluations for source selections more than three years after contract completion, they shall nevertheless be retained in the contract file as provided in FAR 4.8, Government Contract Files.

PART 1853—FORMS

1853.242–72 [Added]

3. Section 1853.242–72 is added to read as follows:

1853.242–72 Evaluation of Performance (NASA Form 1680).

NASA Form 1680, Evaluation of Performance. Prescribed in 1842.1503.

[FR Doc. 98–13511 Filed 5–20–98; 8:45 am]

BILLING CODE 7510–01–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 229

[Docket No. 970129015–8123–06; I.D. 042798B]

RIN 0648–AI84

Taking of Marine Mammals Incidental to Commercial Fishing Operations; Pacific Offshore Cetacean Take Reduction Plan Regulations; Technical Amendment

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

ACTION: Final rule; technical amendment.

SUMMARY: NMFS issues this document to correct and clarify the meaning of a final rule to reduce bycatch of several marine mammal stocks that occur incidental to fishing for swordfish and thresher shark with drift gillnet gear offshore California and Oregon. These amendments are nonsubstantive.

DATES: Effective May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Irma Lagomarsino, NMFS, Southwest Region, 562–980–4016; or Victoria Cornish, NMFS, Office of Protected Resources, 301–713–2322.

SUPPLEMENTARY INFORMATION:

Background

On October 3, 1997 (62 FR 51805), NMFS published a final rule requiring new training, equipment, and gear modifications for operators and vessels in the California/Oregon drift gillnet fishery for thresher shark and swordfish to reduce the mortality and serious injury of several marine mammal stocks that occurs incidental to fishing operations. The regulatory text was codified in subpart C of 50 CFR part 229.

Amendments to 50 CFR Part 229

NMFS has determined that the meaning of term ''extender'' might be unclear to some readers. An ''extender'' is a line that attaches a buoy (float) to a drift gillnet's floatline. To clarify this term, NMFS is adding a definition for ''extender'' to § 229.31(b).

Since floatlines are attached at the top of drift gillnets, the length of extender lines determine the depth in the water column at which the net is fished. NMFS intended the final rule to require that all extenders used in the fishery be at least 6 fathoms (36 ft., 10.9 m) long because the length of extenders controls the depth the net is fished in the water column. The depth of the net in the water column is correlated with marine mammal bycatch; observer data indicate that nets deployed shallower in the water column entangle more marine mammals. However, the word, ''all'' was inadvertently omitted from the regulatory text. NMFS is clarifying that ''all'' extenders deployed must be at least 6 fathoms (36 ft., 10.9 m) long during all sets under § 229.31(b). Accordingly, since floatlines are attached to the top of the nets, all floatlines must be fished at a minimum of 36 feet (10.9 m) below the surface of the water.

NMFS is removing the outdated reference to ''October 30, 1997'' under § 229.31(c)(2).

Also, in the same section, the final rule requires that, while at sea, drift gillnet vessels with multifilament gillnets on board must carry enough pingers to meet the configuration requirements set forth under § 229.31(c)(3). The goal of this requirement is to facilitate enforcement of the pinger requirement during at-sea boardings by enforcement agents onto drift gillnet vessels that are not actively fishing. The term ''multifilament'' was intended to identify the typical gear type used in the fishery and not to describe a narrow class of fishing vessels. NMFS believes that any vessel that could potentially fish in the fishery should have the required number of pingers on board at all times while at sea. To ensure that the final rule remains inclusive, NMFS is deleting the term ''multifilament'' under § 229.31(c)(2).

NMFS is also adding a figure to part 229 which illustrates the pinger configuration and extender requirements (see figure 1).

Classification

The Assistant Administrator for Fisheries, NOAA (AA) has determined that this final rule, technical amendment, makes only minor, non-substantive changes and does not change operating practices in the fishery. Therefore, there is good cause under 5 U.S.C. 553(b)(B) to waive the requirement for prior notice and an opportunity for public comment. Such

procedures are unnecessary. Because this rule makes no substantive changes to the existing regulations, it is not subject to a delay of effective date under 5 U.S.C. 553(d).

As this rule is not subject to the requirement to provide prior notice and an opportunity for public comment under 5 U.S.C. 553, or any other law, the analytical requirements of the Regualtory Flexibility Act, 5 U.S.C. 601 *et seq.*, are inapplicable.

This rule is exempt from review under E.O. 12866.

List of Subjects in 50 CFR Part 229

Administrative practice and procedure, Confidential business information, Fisheries, Marine mammals, Reporting and recordkeeping requirements.

Dated: May 15, 1998.

Gary C. Matlock,

Acting Assistant Administrator for Fisheries, National Marine Fisheries Service.

For the reasons set out in the preamble, 50 CFR part 229 is amended as follows:

PART 229–AUTHORIZATION FOR COMMERCIAL FISHERIES UNDER THE MARINE MAMMAL PROTECTION ACT OF 1972

1. The authority citation for part 229 continues to read as follows:

Authority: 16 U.S.C. 1361 *et seq.*

2. In § 229.31, paragraphs (b) and (c)(2) are revised to read as follows:

§ 229.31 Pacific Offshore Cetacean Take Reduction Plan.

* * * * *

(b) Extenders. An *extender* is a line that attaches a buoy (float) to a drift gillnet's floatline. The floatline is attached to the top of the drift gillnet. All extenders (buoy lines) must be at least 6 fathoms (36 ft; 10.9 m) in length during all sets. Accordingly, all floatlines must be fished at a minimum of 36 feet (10.9 m) below the surface of the water.

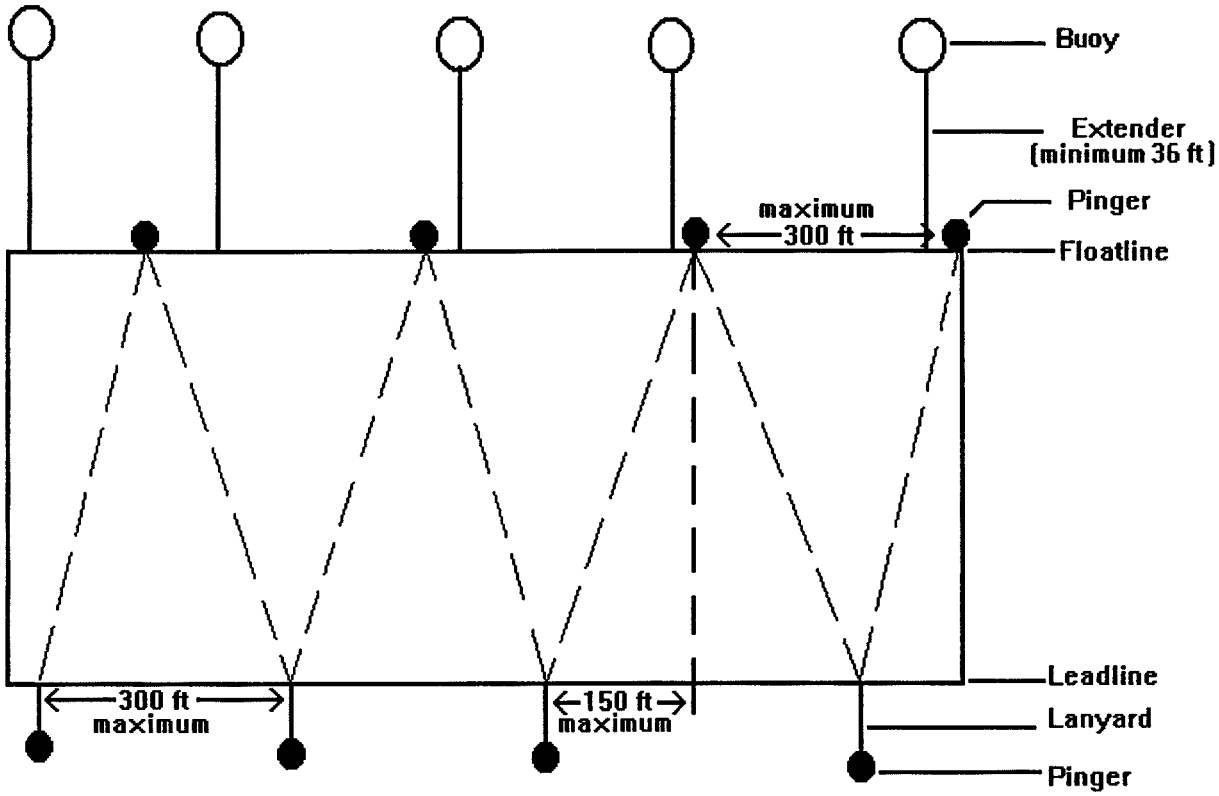
(c) * * *

(2) While at sea, drift gillnet vessels with gillnets onboard must carry enough pingers to meet the configuration requirements set forth under paragraph (c)(3) of this section.

* * * * *

3. Figure 1 to part 229 is added to read as follows:

Figure 1 -- Drift Gillnet Pinger Configuration and Extender Requirements



[FR Doc. 98–13498 Filed 5–20–98; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 285

[Docket No. 980320071–8128–02; I.D. 012198C]

RIN 0648–AK87

Atlantic Tuna Fisheries; Atlantic Bluefin Tuna Annual Quota Specifications and Effort Controls

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

ACTION: Final specifications; final rule.

SUMMARY: NMFS announces specifications and amends the regulations for the Atlantic tuna fisheries to set annual Atlantic bluefin tuna (ABT) fishing category quotas and General category effort controls. These specifications and amendments are necessary to implement the 1996 recommendation of the International Commission for the Conservation of Atlantic Tunas (ICCAT) required by the Atlantic Tunas Convention Act (ATCA) and to achieve domestic management objectives.

DATES: The final specifications are effective May 15, 1998. The amendment to 50 CFR 285.22 (a)(3) is effective June 22, 1998.

ADDRESSES: Copies of supporting documents, including a Final Environmental Assessment-Regulatory Impact Review (EA/RIR), are available from Rebecca Lent, Chief, Highly Migratory Species Management Division, Office of Sustainable Fisheries (F/SF1), NMFS, 1315 East-West Highway, Silver Spring, MD 20910-3282.

FOR FURTHER INFORMATION CONTACT: Mark Murray-Brown at 978-281-9260; or Sarah McLaughlin at 301–713–2347.

SUPPLEMENTARY INFORMATION: The Atlantic tuna fisheries are managed under the authority of ATCA. ATCA authorizes the Secretary of Commerce (Secretary) to issue regulations as may be necessary to carry out the recommendations of ICCAT. The authority to issue regulations has been delegated from the Secretary to the Assistant Administrator for Fisheries, NOAA (AA).

ICCAT has identified the western stock of ABT as overexploited and recommends fishing quotas for contracting parties. Based on the 1996 revised stock assessment, parties at the 1996 meeting of ICCAT adopted a recommendation to increase the annual scientific monitoring quota of ABT in the western Atlantic Ocean from 2,200 metric tons (mt) to 2,354 mt. The share allocated to the United States was increased from 1,306 mt to 1,344 mt to apply each year for the 1997 and 1998 fishing years. NMFS amended the Atlantic tuna fisheries regulations in 1997 to implement that ICCAT recommendation as required by ATCA.

Background information and rationale for these specifications were provided in the preamble to the proposed specifications (63 FR 16220, April 2, 1998) and are not repeated here. These specifications allocate the total ICCAT-recommended quota among the several established fishing categories.

Changes From the Proposed Specifications

Based on recently revised estimates of recreational landings for 1997, NMFS has determined that 4 mt remained unharvested in the Angling category at the end of 1997. Therefore, the final specifications set the 1998 Angling category quota at 269 mt and the large school/small medium subquota at 153 mt, with 81 mt to the northern area and 72 mt to the southern area. These estimates remain preliminary. Should further revisions to the 1997 recreational landings estimates require, NMFS will effect inseason adjustments as necessary.

Based on consideration of comments received during the 30-day comment period, the following changes are made to the final specifications. Three additional restricted-fishing days are established for July in order to extend the fishery for the June-August time period. In addition, August 1 is substituted for August 2. August 2 had been proposed because it followed last year's pattern for August (Sundays, Wednesdays, and market-related days); however, August 1, which is a market-related date, is preferable.

Based on comments received, a revision is also made to the regulatory text at 50 CFR part 285. Section 285.22(a)(3) is amended to allow for more flexible timing of the New York Bight set-aside allocation, e.g., prior to October. The New York Bight set-aside will be implemented when it is determined that ABT have migrated to the New York Bight area and when the coastwide General category is closed.

These changes to the specifications and regulatory text will improve NMFS' ability to implement the ICCAT recommendation and to further the management objectives for the Atlantic tuna fisheries.

Fishing Category Quotas

No changes have been made to the baseline quotas established for 1997. However, the ICCAT recommendation allows, and U.S. regulations require, the addition of any underharvest in 1997 to that same category for 1998. Therefore, NMFS adjusts the 1998 quotas for the ABT fishery to account for underharvest in 1997. The ABT fishing category quotas for the 1998 fishing year are as follows: General category–657 metric tons (mt); Harpoon category-–53 mt; Purse Seine category–-250 mt; Angling category—269 mt; Incidental category–-114 mt; and Reserve–-52 mt.

The Angling category is subdivided as follows: School ABT—108 mt (consistent with the ICCAT limitation on annual catch of school ABT to 8 percent by weight of the total annual domestic quota, i.e., 1,344 mt), with 57 mt to the northern area (New Jersey and north) and 51 mt to the southern area (Delaware and south); large school/small medium ABT—153 mt, with 81 mt to the northern area and 72 mt to the southern area; large medium/giant ABT—8 mt, with 3 mt to the northern area and 5 mt to the southern area.

The Incidental category is subdivided as follows: 89 mt to longline vessels operating south of 34° N. lat.; 24 mt to longline vessels operating north of 34° N. lat.; and 1 mt to vessels using other gear authorized for incidental take.

The General category is distributed as follows, based upon historical catch patterns (1983-96): 60 percent for June-August, 30 percent for September, and 10 percent for October-December. These percentages will be applied only to the adjusted coastwide General category of 647 mt, with the remaining 10 mt being reserved for the New York Bight fishery. The New York Bight set-aside area was redefined in 1997 as the area comprising the waters south and west of a straight line originating at a point on the southern shore of Long Island at 72°27' W. long. (Shinnecock Inlet) and running SSE 150° true, and north of 38°47' N. lat. Thus, of the 647 mt, 388 mt will be available in the period beginning June 1 and ending August 31; 194 mt will be available in the period beginning September 1 and ending September 30; and 65 mt will be available in the period beginning October 1 and ending December 31.

When the coastwide General category fishery has been closed in any quota period, NMFS may publish a notification in the **Federal Register** to make available up to 10 mt of the quota set aside for the New York Bight area.

The daily catch limit for the set-aside area will be one large medium or giant ABT per vessel per day. Upon the effective date of the set-aside fishery, fishing for, retaining, or landing large medium or giant ABT is authorized only within the set-aside area. Any portion of the set-aside amount not harvested prior to the reopening of the coastwide General category fishery in the subsequent quota period may be carried over for the purpose of renewing the set-aside fishery at a later date.

Attainment of the subquota in any quota period will result in a closure until the beginning of the following quota period. The subquota for the following quota period will be adjusted by any underharvest or overharvest in the previous quota period. Announcements of inseason closures will be filed with the Office of the Federal Register, stating the effective date of closure, and will be disseminated by the Highly Migratory Species (HMS) Fax Network, the Atlantic Tunas Information Line, NOAA weather radio, and Coast Guard Notice to Mariners. Although notification of closure will be provided as far in advance as possible, fishermen are encouraged to call the Atlantic Tunas Information Line to check the status of the fishery before leaving for a fishing trip. The phone numbers for the Atlantic Tunas Information Line are (301) 713-1279 and (978) 281-9305. Information regarding the Atlantic tuna fisheries is also available through NextLink Interactive, Inc., at (888) USA-TUNA.

Restricted-Fishing Days

NMFS has added 3 restricted fishing days in July to the proposed schedule of restricted fishing days in order to extend the fishery for the June-August time period. July 8 and 25 are added to coordinate with Japanese market closure dates and July 19, which is a Sunday on which higher catch rates are anticipated. Accordingly, persons aboard vessels permitted in the General category are prohibited from fishing (including tag and release fishing) for ABT of all sizes on the following days: July 8, 15, 16, 19, 22, 25, and 29; August 1, 5, 9, 11, 12, 13, 16, 19, 23, 26, and 30; and September 2, 6, 9, 13, 16, 19, 20, 23, 27, and 30. These restricted fishing days will improve distribution of fishing opportunities without increasing ABT mortality.

Comments and Responses

General Category Quota

Comment: NMFS received several comments that the Reserve does not need to be increased given NMFS' ability to closely monitor the fishery and should be allocated to the General category now rather than at the end of the year, so that the historical ratio of landings before and after September 1 is preserved. Last year, 70 mt were transferred into the General category effective October 1. General category fishermen in the northern New England area feel that this action favored southern New England fishermen because of the location of ABT in the fall.

Response: To ensure that the United States does not exceed its quota and for scientific research and monitoring purposes, NMFS is maintaining the Reserve as proposed (52 mt for 1998).

Harpoon Category Quota

Comment: NMFS received over 100 comments that 15 mt of the Reserve should be allocated to the Harpoon category at the beginning of the season. The commenters do not think that it is fair that the General and Angling categories, which have had their annual quotas increased through initial allocation and inseason actions, may again receive some of the Reserve while the Harpoon category has remained at the same quota level since 1992.

Response: As stated in the 1997 final quota specifications, NMFS takes into consideration the contribution of each fishing category to catch-per-unit-effort (CPUE) indices for the purposes of stock assessment when allocating the quota. Because catch rates are strongly influenced by weather and sea conditions and many harpooners use spotter aircraft to assist in the location of ABT, it is difficult to standardize CPUE from the harpoon fishery. Although Harpoon fishery data could potentially be incorporated into an index of abundance, such an index would be less reliable than the existing rod and reel based index which covers a larger number of years, fishing areas, and size classes. NMFS is not allocating any additional quota to the Harpoon category at this time; however, longterm quota allocations are being considered by the HMS Advisory Panel (HMS AP) during the development of the fishery management plan (FMP).

Angling Category Quota

Comment: NMFS received several comments from commercial fishermen to reduce the Angling category quota, which has increased over recent years even when the quota has been exceeded. Recreational fishermen requested reallocation of quota from the commercial categories to the Angling category because of increased participation and the economic impact on the recreational fishing industry.

Response: Because longterm quota allocations will be addressed by the HMS AP, no changes are made to the Angling category quota in the final specifications. Reallocation of quota to or from the Angling category to or from other categories or the Reserve would require further environmental and economic analyses due to changes in the size composition of landings.

Purse Seine Category Quota

Comment: NMFS received several comments, mostly from recreational fishermen, that the Purse Seine category quota should be reduced (e.g., by 50 percent) or eliminated and that the quota be reallocated to the General and Angling categories.

Some purse seiners submitted comments in support of the status quo, and some indicated that the quota should return to the pre–1995 level of 301 mt, although not at the expense of other categories. One individual commented that NMFS should treat the Purse Seine category like other categories; overharvest should be deducted from the Reserve or from the following year's quota, with no additional penalty, and underharvest should be added to the following year's quota, in accordance with ICCAT recommendations.

Response: Because longterm quota allocations will be addressed by the HMS AP, no changes are made to the Purse Seine category quota in the final specifications. Reallocation of quota to or from the Purse Seine category to or from other categories or the Reserve would require further environmental and economic analyses due to changes in the size composition of landings. NMFS is required to add any underharvest to the same category for the following year when there is an ICCAT recommendation to do so.

Incidental Category Quota

Comment: One commenter argued that the late-season transfer of quota from the Incidental category to other categories should be returned to the Incidental category. The commenter recognized that, when this issue was addressed at the January HMS AP meeting, members supported leaving the transferred quota in the General category for the 1998 fishing season, especially since the Incidental category is not likely to be filled. The commenter urged NMFS not to set such a precedent and to address the restrictive catch limits that result in the inability of longline vessels to meet their quotas.

Response: The primary issue regarding Incidental category quota allocation is the recommendation of ICCAT to reduce dead discards of ABT. This issue will be examined in the coming months as HMS prepares a proposed rule to implement that ICCAT recommendation. Once such measures are in place, NMFS may consider the longterm quota needs for this category. Therefore, NMFS maintains the status quo allocation at this time.

Time Period Subquotas

Several commenters believe that the 10 percent allocated to the General category for October should be divided between June-August and September. Some commenters proposed that the quota be divided as follows: 25 percent for June, 25 percent for July, 25 percent for August, and 25 percent for September through December. Other commenters supported an allocation of 50 percent for June through August, 35 percent for September, and 15 percent for October through December, plus a 25–mt set-aside for the New York Bight area. They also requested that NMFS be flexible regarding the opening date of the New York Bight set-aside fishery; i.e., make the quota available when ABT are present in the Mud Hole area.

Response: NMFS maintains the status quo time period subquota breakdown in these final specifications. Longterm effort control issues will be addressed by the AP in the course of FMP development. In addition, NMFS maintains the New York Bight set-aside at 10 mt. However, NMFS amends the regulations in conjunction with these final specifications to allow for more flexible timing of the New York Bight set-aside allocation. The 1997 regulations specified that only when the third period (October through December) General category catch was projected to have reached 65 mt, would NMFS open the fishery for the remaining 10 mt of the General category quota for the New York Bight set-aside. Through this final rule, NMFS amends the regulations in to allow more flexibility in managing the New York Bight set-aside, by permitting the implementation of the set-aside earlier than October, if necessary.

Restricted Fishing Days (RFDs)

Comment: A organization representing General category fishermen requested additional days for July through October to correspond with Japanese market closure dates or to enhance General category fishing opportunities and scientific monitoring by extending the season. Other commenters felt that RFDs should be scheduled for the first half of July in the same manner as used for the second half of July. Many others felt that RFDs do not help increase market prices and are burdensome to fishermen that could otherwise fish for other species or take care of other business after the ABT season closes.

Other commenters preferred to have more fishing days with low catch rates early in the season (June through August) as opposed to only a few fishing days with high catch rates late in the season. They noted that a late season fishery (September/October) may be to the detriment of the northern New England fishery while benefitting the Southern New England (Cape Cod and Islands) fishery due to migration patterns of ABT in the fall.

NMFS also received a comment that the General category RFDs should be implemented for the Harpoon category as well to extend the Harpoon category season, and some commercial fishermen commented that tagging and releasing ABT should be allowed on RFDs for scientific monitoring purposes.

Response: NMFS has added 3 restricted fishing days in July to the proposed schedule of restricted fishing days in order to extend the fishery for the June-August time period. July 8 and 25 are added to coordinate with Japanese market closure dates, and July 19 is added, which is a Sunday on which higher catch rates are anticipated. In addition, NMFS is substituting August 1 for August 2. August 2 had been proposed because it followed last year's pattern for August (Sundays, Wednesdays, and market-related days); however, August 1, which is a market-related date, is preferable.

Because the October through December allocation is small, HMS believes that October RFDs would not appreciably extend the fishery. Also, weather is unpredictable in the October fishery, and poor sea conditions may limit participation. Should enough quota be transferred to the late season fishery to merit RFDs, NMFS could adjust the effort control calendar with a minimum 3-day notification to fishermen. NMFS maintains that, for enforcement reasons, all fishing for ABT should be prohibited on RFDs. At this time, NMFS does not intend to implement RFDs for the Harpoon category. One of the main purposes of the RFDs is to extend the season in the General category in order to collect CPUE data. As the Harpoon category is not used for collecting this type of information, RFDs are not necessary.

Spotter Aircraft

Comment: Although the use of spotter aircraft was not addressed in the proposed specifications, NMFS requested further comment on issues to be considered by the HMS AP for the HMS FMP and to implement future ICCAT recommendations. Many commenters felt that spotter aircraft use by vessels permitted in the Harpoon category should be prohibited for reasons of fairness, safety, and/or enforceability. Most commenters indicated that aircraft should continue to be used only by Purse Seine vessels.

Response: NMFS intends to gather more public comments and data, and would need to conduct further analyses on this issue prior to making any changes to the regulations. This issue will be considered by the HMS AP during FMP deliberations.

Other Comments

Angling category season. Mid-Atlantic commenters requested that NMFS establish ''date-certain'' seasons, whereby the Angling category fishery in a particular area will be opened at the appropriate time (when ABT are in the area) for a period of 30 days, at a designated catch limit. This would improve trip planning for Charter/Headboat captains.

Angling category geographical areas. There was some support for moving the north/south boundary from Delaware Bay to off Beach Haven, New Jersey. Others supported a third zone, intended to increase fishing opportunities in the Mid-Atlantic region. Others oppose the creation of a third zone because of the potential monitoring difficulties.

General category set-asides. NMFS received requests from North Carolina fishermen for a portion of the General category quota to allow General category and Charter/Headboat category fishermen to land and sell large medium and giant ABT in the winter months (November-December). NMFS also received requests for a set-aside for the Connecticut/Rhode Island/New York area. Many General category participants have opposed new set-asides, especially for North Carolina.

General/Angling category separation. Some commenters opposed the prohibition on recreational fishing by General category permit holders because the fishery comprises mixed size classes and trip planning is difficult when vessels are limited to one quota category.

Charter/Headboat catch limits. Some commenters opposed the new regulation that requires Charter/Headboats to fish under either the General category or

Angling category catch limits, based on the size of the first ABT retained. Some Charter/Headboat constituents found that the restriction puts undue burden on their daily fishing practices and encourages waste through discarding or highgrading. NMFS received a suggestion for a sliding scale of increasing catch limits based on Coast Guard documented passenger capacity of a Charterboat. This would enable larger boats to attract business.

Angling category monitoring. Some commenters opposed the coastwide expansion of the recreational harvest tagging pilot program in North Carolina and the use of permits to monitor the recreational fishery; enhancement of the Large Pelagic Survey is preferred.

Gear types. NMFS received several comments from spearfishermen requesting that they be allowed to spear tunas, specifically ABT. The requesters stated that they would have a minimal impact on the fishery due to the small subquota and number of fishermen involved.

Several commenters objected to the prohibition on harpoon gear in the Charter/Headboat permit category. Some argued that the harpoon is critical to safely boat an ABT and is currently in widespread use. Other commenters would like to use harpoons as fishing gear in the Charter/Headboat category while fishing for large medium, and giant ABT.

Response: NMFS intends to address the specific issue of Angling category catch limits and time/area openings and closures during the season through existing regulatory authority in order to enhance fishing opportunities for Angling category participants coastwide. Comments regarding the appropriate distribution will be considered as NMFS effects inseason adjustments.

Temporal and geographic subdivisions for all categories, quota monitoring, and modifications of catch limits and gear types are issues under discussion by NMFS and the HMS AP as a comprehensive HMS FMP is being developed. Therefore, NMFS will not address these issues in these final quota and effort control specifications, pending further consideration and appropriate analyses.

Reminder of Recent Changes for the General and Charter/Headboat Permit Categories

NMFS published by final rule on June 5, 1997 (62 FR 30741), a measure that was effective January 1, 1998, prohibiting persons aboard vessels permitted in the General category from retaining ABT less than the large medium size class. This action effectively separated the commercial and recreational fisheries, with the exception of charter/headboats.

In the same final rule, NMFS specified that anglers aboard vessels permitted in the Charter/Headboat category may collectively fish under either the daily Angling category limits or the daily General category limit as applicable on that day. The size category of the first ABT retained or possessed will determine the fishing category of all persons aboard the vessel and the applicable catch limits for that day. On designated restricted fishing days, persons aboard vessels permitted in the Charter/Headboat category may fish for school, large school, and small medium ABT only, provided the Angling category remains open, and are subject to the Angling category catch limits in effect.

Classification

These final specifications and regulatory amendments are published under the authority of the ATCA, 16 U.S.C. 971 *et seq*. The AA has determined that these specifications and amendments are necessary to implement the recommendations of ICCAT and are necessary for the management of the Atlantic tuna fisheries.

The Assistant General Counsel for Legislation and Regulation of the Department of Commerce has certified to the Chief Counsel for Advocacy of the Small Business Administration that the proposed specifications, if implemented, would not have a significant economic impact on a substantial number of small entities. This determination remains valid for the final specifications/final rule. Therefore, no Regulatory Flexibility Analysis was prepared.

These quota and effort control specifications impose no requirements with which fishermen will have to come into compliance, and are necessary to help ensure that the U.S. actions are consistent with its international obligations at ICCAT. Therefore, NMFS has determined that there is good cause to waive the 30-day delay in the effective date normally required by 5 U.S.C. 553(d). NMFS will rapidly communicate these final specifications through the FAX network and NOAA weather radio.

These final specifications and regulatory amendments have been determined to be not significant for purposes of E.O. 12866.

List of Subjects in 50 CFR Part 285

Fisheries, Fishing, Penalties, Reporting and recordkeeping requirements, Treaties.

Dated: May 15, 1998.

Gary C. Matlock,

Acting Assistant Administrator for Fisheries, National Marine Fisheries Service.

For the reasons set out in the preamble, 50 CFR part 285 is amended as follows:

PART 285–ATLANTIC TUNA FISHERIES

1. The authority citation for part 285 continues to read as follows:

Authority: 16 U.S.C. 971 *et seq.*

2. In § 285.22, paragraph (a)(3) is revised to read as follows:

§ 285.22 Quotas.

* * * * *

(a) * * *

(3) When the coastwide General category fishery has been closed in any quota period under paragraph (a)(2) of this section, the Director may publish a notification in the **Federal Register** to make available up to 10 mt of the quota set aside for an area comprising the waters south and west of a straight line originating at a point on the southern shore of Long Island at 72°27' W. long. (Shinnecock Inlet) and running SSE 150° true, and north of 38°47' N. lat. The daily catch limit for the set-aside area will be one large medium or giant ABT per vessel per day. Upon the effective date of the set-aside fishery, fishing for, retaining, or landing large medium or giant ABT is authorized only within the set-aside area. Any portion of the set-aside amount not harvested prior to the reopening of the coastwide General category fishery in the subsequent quota period established under paragraph (a)(1) of this section may be carried over for the purpose of renewing the set-aside fishery at a later date.

* * * * *

[FR Doc. 98–13521 Filed 5–18–98; 1:32 pm]

BILLING CODE 3510–22–F

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 971015246–7293–02; I.D. 051498C]

Fisheries of the Northeastern United States; Scup Fisheries; Rescission of 1998 Summer Period Scup Fisheries Closures in Delaware, New Hampshire, Maryland, and Massachusetts

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

ACTION: Rescission of closures.

SUMMARY: NMFS issues this notification announcing the rescission of closures previously issued for the Delaware, New Hampshire, Massachusetts, and Maryland Summer period scup fisheries for 1998. This rescission is in compliance with an April 27, 1998, Order of the United States District Court for Massachusetts (Court), which voided state-by-state allocation of the Summer period commercial scup fishing quota. The public is advised that landings are allowed for the Summer period in Delaware, New Hampshire, Maryland, and Massachusetts and that the quota is being administered on a coastwide basis.

DATES: Effective May 18, 1998.

FOR FURTHER INFORMATION CONTACT: Regina L. Spallone, Fishery Policy Analyst, 978–281–9221.

SUPPLEMENTARY INFORMATION: NMFS, in compliance with regulations found at 50 CFR 648.120, closed the 1998 scup Summer period commercial fisheries of Delaware and New Hampshire (62 FR 66304, December 18, 1997), Massachusetts (63 FR 3478, January 23, 1998), and Maryland (63 FR 23227, April 28, 1998) after determining through quota adjustments that these States had used their entire available Summer period commercial scup quota. These closures were to be effective May 1, 1998, through October 31, 1998.

In response to a lawsuit filed by the Commonwealth of Massachusetts, the Court, on April 27, 1998, ordered that the state-by-state allocation system for the summer commercial scup fishery, as codified in 50 CFR 648.120, is void. Since the state closures were triggered by the state-by-state allocation system required under 50 CFR 648.120, the basis for closing these fisheries is removed, and the closures are rescinded. The 1998 Summer period quota of 1,780,794 lb (807,755 kg) will be administered on a coastwide basis.

Classification

This action is required by 50 CFR part 648 and is exempt from review under E.O. 12866.

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

Dated: May 15, 1998.

Gary C. Matlock,

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

[FR Doc. 98–13497 Filed 5–18–98; 9:52 am]

BILLING CODE 3510–22–F

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 648

[Docket No. 09–302051–8119–02; I.D. 021198B]

RIN 0648–AK78

Fisheries of the Northeastern United States; Fishery Management Plan (FMP) for the Summer Flounder, Scup, and Black Sea Bass Fisheries; Recreational Measures for the 1998 Summer Flounder, Scup, and Black Sea Bass Fisheries

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

ACTION: Final rule.

SUMMARY: NMFS issues this final rule to amend the regulations implementing the FMP for the Summer Flounder, Scup, and Black Sea Bass Fisheries. This rule implements a possession limit of eight fish per person and a minimum fish size of 15 inches (38 cm) for the 1998 summer flounder recreational fishery; a minimum fish size of 10 inches (25.4 cm) and an August 1 through August 15 seasonal closure for the 1998 black sea bass recreational fishery; and no change in the current regulations for the 1998 scup recreational fishery. The intent of this rule is to comply with the regulations implementing the FMP for the fisheries that require NMFS to implement measures for the upcoming fishing year that will prevent overfishing of these resources.

DATES: Effective June 22, 1998.

ADDRESSES: Copies of the Environmental Assessment prepared for the 1998 summer flounder, scup, and black sea bass specifications and supporting documents used by the Monitoring Committee are available from: Executive Director, Mid-Atlantic Fishery Management Council, Room 2115, Federal Building, 300 S. New Street, Dover, DE 19901–6790.

FOR FURTHER INFORMATION CONTACT: David M. Gouveia, Fishery Management Specialist, (978) 281–9280.

SUPPLEMENTARY INFORMATION: The FMP was developed jointly by the Mid-Atlantic Fishery Management Council (Council) and the Atlantic States Marine Fisheries Commission (Commission), in consultation with the New England and South Atlantic Fishery Management Councils. Implementing regulations for the fishery are found at 50 CFR part 648.

Sections 648.100, 648.120, and 648.140 outline the process for determining annual commercial and recreational catch quotas and other restrictions for the summer flounder, scup, and black sea bass fisheries. Pursuant to these sections, the Administrator, Northeast Region, NMFS, implements measures for the fishing year to ensure achievement of the fishing mortality rate specified in the FMP. This document announces the following measures pertaining to the recreational fishery, which are unchanged from the proposed measures that were published in the **Federal Register** on March 17, 1998 (63 FR 13208): (1) An individual possession limit of eight fish per person and a minimum fish size of 15 inches (38 cm) for the 1998 summer flounder recreational fishery; (2) a minimum fish size of 10 inches (25.4 cm) and an August 1 through August 15 seasonal closure for the 1998 black sea bass recreational fishery; and (3) no-change in the current regulations for the 1998 scup recreational fishery (a minimum fish size of 7 inches (17.78 cm)). The preamble to the proposed rule provided background concerning the development of these measures and that information is not repeated here.

In addition to these measures, the Council and Commission considered measures to reduce discard mortality associated with the recreational fishery. Discard mortality was addressed for the commercial fishery by requiring each state to establish a 15 percent commercial quota set aside for a bycatch fishery. The Council intended to recommend a recreational hook requirement to address discard mortality in that sector.

However, Commission staff presented the results of a literature review that revealed few available studies available on which to base hook size requirements for summer flounder. Therefore, the Council and Commission took action based on the limited studies available and testimony from fishery participants. During the 1998 fishery,

the Council and Commission intend to publicize their support for the voluntary use of circle hooks greater than 2/0 in size when fishing for summer flounder. Given the absence of definitive data, this appears to be a reasonable way to begin to address this issue for the recreational fishery.

Comments and Responses

Two comments were received immediately after the Council meeting in December 1997. One comment was received during the comment period for the proposed rule, which ended April 16, 1998.

Comment 1: New Jersey Congressman Frank Pallone supports a 14.5–inch (36.8–cm) minimum fish size, eight fish per person possession limit, and a May 15 to October 15 open season for summer flounder; and a 9.5–inch (24.1–cm) minimum fish size and a ''reasonable seasonal restriction'' for black sea bass. Congressman Pallone feels that the proposed summer flounder and black sea bass recreational specifications will have a greater negative impact on the New York and New Jersey area than on any other area in the Mid-Atlantic region.

Response: NMFS notes that the FMP calls for substantial reductions in commercial and recreational harvests of both summer flounder and black sea bass coastwide in 1998. Summer flounder measures are intended to achieve a 20.2–percent reduction from 1997 catches. The Congressman proposed a less restrictive minimum fish size for summer flounder than those recommended by the Council and published in the proposed rule. The seasonal closure supported by the Congressman appears to be intended to provide the additional reductions in catch required for 1998. NMFS notes that the Council had an extended discussion about including a closed season in the recreational measures for summer flounder for 1998. That discussion identified several concerns that are unresolved by the Congressman's proposal.

First, the seasonal restriction would require the fishery to be closed from January 1 through May 14, as well as from October 16 through December 31. However, this final rule will not be published until April or May. Therefore, the first portion of the Congressman's proposed closed season could not be implemented for 1998. Second, because summer flounder migrate seasonally, it is difficult to specify a closed season that will achieve a consistent reduction throughout the geographic range of the species. The Council discussed closed seasons at length and several Council members expressed concern that closures in either spring or fall would have disproportionate negative impacts upon such southern states as Virginia and North Carolina. There is no evidence that any particular state will be affected disproportionately.

The 1998 black sea bass measures are intended to achieve landings that are a 47–percent reduction from those in 1996 (the last year for which complete landings are available). The Congressman supports a 9.5–inch (24.1–cm) minimum fish size with a ''reasonable seasonal restriction.'' Since the minimum fish size supported by the Congressman is less restrictive than that adopted here, the seasonal restriction would have to be more restrictive in order to meet the reduction necessary. At the December 1997 Council meeting, Council members and the public in attendance focused on three potential management tools available for managing the black sea bass fishery: an individual possession limit, minimum fish size, and seasonal restrictions. In that discussion, as well as in the recommendations of the Monitoring Committee, of the Industry Advisors and, ultimately, of the Council, consensus was that an increase to a 10–inch (25.4–cm) minimum fish size and a 15-day closure was preferable to restrictive possession limits or additional seasonal restrictions. In fact, the Council's Industry Advisors noted that they had agreed that a 10–inch (25.4–cm) size limit would have fewer negative effects than any other potential management measures on all user groups. The Congressman did not explain why he preferred a 9.5–inch (24.1–cm) minimum fish size to a 10–inch (25.4–cm) minimum fish size or what he would consider a ''reasonable'' seasonal closure.

Finally, the Congressman noted that the proposed measures will have a more severe impact upon fishery participants in New York and New Jersey than in any other states. NMFS recognizes that the recreational fishery is important to these states, but is not convinced that this conclusion is supported. In fact, during the Council discussion, several members noted concern that the increase in the summer flounder minimum fish size would be more restrictive in such southern states as Virginia and North Carolina than in the northern portions of the management area. NMFS concludes that specific measures may have somewhat different impacts geographically, but, overall, NMFS determined that the rule would not have a significant impact upon a substantial number of small entities, which would affect New York and New Jersey disproportionately (see **Classification** section).

Comment 2: The State of Maryland Department of Natural Resources (DNR) commented in support of the initial Council proposal, which would allow states to implement a 14.5–inch (36.8–cm) minimum fish size and six fish per person possession limit, and closed season as long as it achieves the same conservation benefit as the 15–inch (38–cm) minimum fish size and the eight fish per person possession limit. DNR expressed serious concern that a minimum fish size of 15 inches (38 cm) would have the effect of denying Maryland harvesters the opportunity to catch legal summer flounder in Chesapeake Bay and, to some extent in other coastal bays.

Response: The FMP does not allow the Council to specify alternative possession limits or minimum fish sizes. At the time the Council made its recommendation, the members specified that, if alternative measures were not allowed, the preferred measure would be the 15–inch (38–cm) minimum fish size and eight fish per person possession limit. It will be necessary to amend the FMP to establish a measure that will allow the Council to specify a set of alternative measures with equivalent conservation benefits from which states may select the set of measures that are most appropriate for their fisheries. NMFS understands that the Council intends to discuss this issue further as part of a future amendment to the FMP.

Recreational survey data suggests that, while the percentage of fish greater than or equal to 15 inches (38 cm) in size in the Chesapeake Bay may be a lower percentage than that in the coast as a whole (60 percent), there are larger fish present in the Bay.

Comment 3: One commenter supported raising the black sea bass minimum size limit to 10 inches (25.4 cm), but has expressed concern regarding the lack of a possession limit and the August 1 through August 15 seasonal closure. The commenter supports a possession limit of 30 fish per person for ''full day'' vessels and 20 fish per person for ''half day'' vessels in the Ocean City, Maryland, area. To accommodate the vessels that make trips longer than 12 hours, the commenter suggests a possession limit of 50 fish per person and a possession limit of 30 fish per person for private and charter vessels conducting trips longer than 12 hours. Additionally, the commenter feels the August closure would have a serious financial impact on the owners and crews of vessels from the Ocean City, Maryland, area and

would ''simply allow for a great September.''

Response: Possession limits were discussed at the December 1997 Council meeting. Marine Recreation Statistical Survey data showed that the average number of black sea bass landed per successful trip was 5.4 in 1996. Council analysis showed that imposing a 10–inch (25.4–cm) minimum size limit and a possession limit as low as seven fish per person would achieve the necessary reduction in recreational black sea bass landings and, on average, allow an additional three fish per person possession. However, at the December 1997 meeting, public comment of those industry members in support of possession limit restrictions strongly supported a greater than 20 fish per person possession limit. As a result of these discussions, the Council and Commission proposed two alternative options that would allow each state to choose either of the two options, one of which did contain a 20 fish per person possession limit. However, the FMP does not allow the Council to specify alternative measures or to adopt measures that differ from those specified by the Council. NMFS did not recommend the 20 fish per person possession limit because the seasonal restriction appears to be more widely accepted based on comments from the December 1997 Council meeting and the comment period for the proposed rule. This is the only comment in opposition.

The commenter's suggestion of ''half day'' versus ''full day'' possession limits is not feasible at this time. To implement this type of measure, a method to track vessel departures and arrivals would have to be developed. Any such system for the recreational sector would be burdensome and not cost effective for the industry. Regarding the commenter's suggestion of allowing an unlimited possession of black sea bass is ''hardly good science,'' Council analysis of the best data available shows that the seasonal closure and minimum fish size implemented in 1998 are expected to constrain anglers by the needed 47 percent in 1998.

The commenter provided no indication of support for seasonal closures in general. While the commenter notes that the proposed seasonal closure will likely have a serious financial impact on owners and crews in the Ocean City, Maryland area, he admits that croaker may replace black sea bass during the August 1 through August 15 closure and that the respite provided by the closure will result in a ''great September.'' As noted in an earlier response, NMFS concludes that specific measures may have somewhat different impacts geographically, but, overall, NMFS determined that the rule would not have a significant impact upon recreational fishermen in this sector. It is likely that recreational anglers will target other species that are relatively more abundant (such as striped bass) when faced with potential reductions in the amount of summer flounder and black sea bass they are allowed to catch due to decreases in the respective recreational harvest limits.

Classification

This action is authorized by 50 CFR part 648.

This final rule has been determined to be not significant for purposes of E.O. 12866.

When this rule was proposed, the Assistant General Counsel for Legislation and Regulation, Department of Commerce, certified to the Chief Counsel for Advocacy of the Small Business Administration that this proposed rule, if adopted, would not have a significant economic impact on a substantial number of small entities. Because no comments were received regarding this certification and the basis for it remains unchanged, a regulatory flexibility analysis was not prepared.

List of Subjects in 50 CFR Part 648

Fisheries, Fishing, Reporting and recordkeeping requirements.

Dated: May 15, 1998.

Gary C. Matlock,

Acting Assistant Administrator for Fisheries, 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: 16 U.S.C. 1801 *et seq.*

2. In § 648.103, paragraph (b) is revised to read as follows:

§ 648.103 Minimum fish sizes.

* * * * *

(b) The minimum size for summer flounder is 15 inches (38 cm) TL for all vessels that do not qualify for a moratorium permit, and party boats holding a moratorium permit if fishing with passengers for hire or carrying more than five crew members, or charter boats holding a moratorium permit if fishing with more than three crew members.

* * * * *

3. In § 648.105, the first sentence of paragraph (a) is revised to read as follows:

§ 648.105 Possession restrictions.

(a) No person shall possess more than eight summer flounder in, or harvested from, the EEZ unless that person is the owner or operator of a fishing vessel issued a summer flounder moratorium permit or is issued a summer flounder dealer permit. * * *

* * * * *

4. Section 648.142 is revised to read as follows:

§ 648.142 Time restrictions.

Vessels that are not eligible for a moratorium permit under § 648.4(a)(6) and fishermen subject to the possession limit may not fish for black sea bass from August 1 through August 15. This time period may be adjusted pursuant to the procedures in § 648.140.

5. In § 648.143, paragraph (a) is revised, existing paragraph (b) is redesignated as paragraph (c), and new paragraph (b) is added to read as follows:

§ 648.143 Minimum fish sizes.

(a) The minimum size for black sea bass is 10 inches (25.4 cm) total length for all vessels issued a moratorium permit under § 648.4(a)(7) that fish for or retain black sea bass in or from U.S. waters of the western Atlantic Ocean from 35°15.3' N. Lat., the latitude of Cape Hatteras Light, North Carolina, northward to the U.S.-Canada border. The minimum size may be adjusted for commercial vessels pursuant to the procedures in § 648.140.

(b) The minimum size for black sea bass is 10 inches (25.4 cm) TL for all vessels that do not qualify for a moratorium permit, and party boats holding a moratorium permit if fishing with passengers for hire or carrying more than five crew members, or charter boats, holding a moratorium permit if fishing with more than three crew members. The minimum size may be adjusted for recreational vessels pursuant to the procedures in § 648.140.

* * * * *

[FR Doc. 98–13595 Filed 5–20–98; 8:45 am]

BILLING CODE 3510–22–F

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 679

[Docket No. 971208298–8055–02; I.D. 051598A]

Fisheries of the Exclusive Economic Zone Off Alaska; Pacific Cod by Vessels Using Hook-and-Line Gear in Bering Sea and Aleutian Islands

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

ACTION: Closure.

SUMMARY: NMFS is closing directed fishing for Pacific cod by vessels using hook-and-line gear in the Bering Sea and Aleutian Islands management area (BSAI). This action is necessary to prevent exceeding the second seasonal apportionment of the 1998 Pacific halibut bycatch allowance specified for the Pacific cod hook-and-line fishery category.

DATES: Effective 1200 hrs, Alaska local time (A.l.t.), May 17, 1998, through 1200 hrs, A.l.t., September 15, 1998.

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

SUPPLEMENTARY INFORMATION: The groundfish fishery in the BSAI exclusive economic zone is managed by NMFS according to the Fishery Management Plan for the Groundfish Fishery of the Bering Sea and Aleutian Islands Area (FMP) prepared by the North Pacific Fishery Management Council under authority of the Magnuson-Stevens Fishery Conservation and Management Act. Fishing by U.S. vessels is governed by regulations implementing the FMP at subpart H of 50 CFR part 600 and 50 CFR part 679.

The second seasonal apportionment of the 1998 Pacific halibut bycatch allowance specified for the Pacific cod hook-and-line fishery in the BSAI, which is defined at § 679.21(e)(5)(ii)(A), was established by the Final 1998 Harvest Specifications of Groundfish for the BSAI (63 FR 12689, March 16, 1998) as 37 mt.

In accordance with § 679.21(e)(9), the Administrator, Alaska Region, NMFS (Regional Administrator), has determined that the second seasonal apportionment of the 1998 Pacific halibut bycatch allowance specified for the Pacific cod hook-and-line fishery in the BSAI has been caught. Consequently, NMFS is prohibiting directed fishing for Pacific cod by vessels using hook-and-line gear in the BSAI.

Maximum retainable bycatch amounts may be found at § 679.20(e) and (f).

Classification

This action responds to the best available information recently obtained from the fishery. It must be implemented immediately to prevent exceeding the second seasonal apportionment of the 1998 Pacific halibut bycatch allowance specified for the Pacific cod hook-and-line fishery in the BSAI. Providing prior notice and an opportunity for public comment on this action is impracticable and contrary to the public interest. The fleet will soon take the apportionment. Further delay would only result in the second seasonal apportionment of the 1998 Pacific halibut bycatch allowance specified for the Pacific cod hook-and-line fishery in the BSAI being exceeded and disrupt the FMP's objective of limiting hook-and-line Pacific halibut mortality. NMFS finds for good cause that the implementation of this action cannot be delayed for 30 days. Accordingly, under U.S.C. 553(d), a delay in the effective date is hereby waived.

This action is required by § 679.21 and is exempt from review under E.O. 12866.

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

Dated: May 15, 1998.

Bruce C. Morehead,

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

[FR Doc. 98–13500 Filed 5–18–98; 9:52 am]

BILLING CODE 3510–22–F

Proposed Rules

Federal Register
Vol. 63, No. 98
Thursday, May 21, 1998

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.

NUCLEAR REGULATORY COMMISSION

10 CFR Part 70

Public Meeting on Part 70 Rulemaking Activities

AGENCY: Nuclear Regulatory Commission (NRC).

ACTION: Notice of meeting.

SUMMARY: NRC will host a public meeting in Rockville, Maryland to discuss issues associated with NRC 10 CFR Part 70 rulemaking activities. This meeting will provide information on the status of staff activities consistent with Commission direction in a Staff Requirements Memorandum (SRM) dated August 26, 1997.

DATES: The meeting is scheduled for May 28, 1998 from 9:00 a.m. to 1:00 p.m. The meeting is open to the public. Persons who wish to attend the meeting should contact Jim Hennigan at (301) 415–6850 at least one week prior to the meeting.

ADDRESSES: NRC's auditorium at Two White Flint North, 11545 Rockville Pike, Rockville, Maryland. Visitor parking around the NRC building is limited; however, the meeting site is located adjacent to the White Flint Station on the Metro Red Line.

FOR FURTHER INFORMATION CONTACT: Lidia Roché, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555, telephone: (301) 415–7830, fax: (301) 415–5390, e-mail: lar2@nrc.gov. Copies of the documents referred to above can be obtained from the NRC public document room. In addition, you can view SECY–97–137 via the Internet at http://www.nrc.gov/NRC/COMMISSION/activities.html.

SUPPLEMENTARY INFORMATION: The purpose of the meeting is to provide information on the status of NRC staff activities pertaining to the revision of 10 CFR Part 70. The focus of the rulemaking under development is on the features recommended in SECY–97–137, ''Proposed Resolution to Petition for Rulemaking Filed by the Nuclear Energy Institute'' (June 30, 1997) which was approved by the Commission in an SRM dated August 26, 1997. The basic elements of the rule under development are 1) the performance of an Integrated Safety Analysis (ISA) by licensees authorized to possess Special Nuclear Material (SNM) in quantities sufficient to constitute a potential for a nuclear criticality; 2) the establishment of limits to identify the adverse consequences that the licensee must protect against; 3) the inclusion of the safety bases in the license; and 4) allowance for licensees to make certain change to their facilities without prior approval by NRC.

Dated at Rockville, Maryland this 15th day of May, 1998.

For the Nuclear Regulatory Commission.

Elizabeth Q. Ten Eyck,

Director, Division of Fuel Cycle Safety and Safeguards.

[FR Doc. 98–13556 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 98–CE–07–AD]

RIN 2120–AA64

Airworthiness Directives; Glaser-Dirks Flugzeugbau GmbH Model DG–400 Gliders

AGENCY: Federal Aviation Administration, DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This document proposes to adopt a new airworthiness directive (AD) that would apply to all Glaser-Dirks Flugzeugbau GmbH (Glaser-Dirks) Model DG–400 gliders. The proposed action would require replacing the propeller shaft, the bearings, and the front drive belt retaining rings with ones of improved design. The proposed AD is the result of mandatory continuing airworthiness information (MCAI) issued by the airworthiness authority for Germany. The actions specified by the proposed AD are intended to prevent failure of the propeller shaft, which could result in loss of glider propulsion during critical phases of flight.

DATES: Comments must be received on or before June 26, 1998.

ADDRESSES: Submit comments in triplicate to the Federal Aviation Administration (FAA), Central Region, Office of the Regional Counsel, Attention: Rules Docket No. 98–CE–07–AD, Room 1558, 601 E. 12th Street, Kansas City, Missouri 64106. Comments may be inspected at this location between 8 a.m. and 4 p.m., Monday through Friday, holidays excepted.

Service information that applies to the proposed AD may be obtained from Glaser-Dirks Flugzeugbau GmbH, Im Schollengarten 19–20, 7520 Bruchsal 4, Germany; telephone: +49 7257–89–0; facsimile: +49 7257–8922. This information also may be examined at the Rules Docket at the address above.

FOR FURTHER INFORMATION CONTACT: Mike Kiesov, Aerospace Engineer, FAA, Small Airplane Directorate, Aircraft Certification Service, 1201 Walnut, suite 900, Kansas City, Missouri 64106; telephone: (816) 426–6934; facsimile: (816) 426–2169.

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 should 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 notice may be changed in light of the comments received.

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 that summarizes 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 notice must submit a self-addressed, stamped postcard on which the following

statement is made: ''Comments to Docket No. 98–CE–07–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, Central Region, Office of the Regional Counsel, Attention: Rules Docket No. 98–CE–07–AD, Room 1558, 601 E. 12th Street, Kansas City, Missouri 64106.

Discussion

The Luftfahrt-Bundesamt (LBA), which is the airworthiness authority for Germany, recently notified the FAA that an unsafe condition may exist on all Glaser-Dirks Model DG–400 gliders. The LBA reports that the propeller shafts installed on some of these Model DG–400 gliders have failed during flight. An LBA investigation of these incidents showed that the propeller shaft currently installed had a torque tensioning problem which was causing the shaft to rotate. In some cases, the propeller drive belt damaged the front retaining rings and came off the upper pulley, which also damaged the propeller.

These conditions, if not corrected, could result in loss of propulsion during critical phases of flight.

Relevant Service Information

DG Flugzeugbau has issued Technical Note No. 826/32, dated July 19, 1996, and DG Flugzeugbau WORKING INSTRUCTION No. 1 for TN 826/32, dated July, 1996, which specifies procedures for replacing the propeller shaft, the bearings, and the front drive belt retaining rings with parts of improved design.

The LBA classified this service bulletin as mandatory and issued German AD 96–243 DG Flugzeugbau, dated August 29, 1996, in order to assure the continued airworthiness of these gliders in Germany.

The FAA's Determination

This glider model is manufactured in Germany and is type certificated for operation in the United States under the provisions of section 21.29 of the Federal Aviation Regulations (14 CFR 21.29) and the applicable bilateral airworthiness agreement. Pursuant to this bilateral airworthiness agreement, the LBA has kept the FAA informed of the situation described above.

The FAA has examined the findings of the LBA; reviewed all available information, including the service information referenced above; and determined that AD action is necessary for products of this type design that are certificated for operation in the United States.

Explanation of the Provisions of the Proposed AD

Since an unsafe condition has been identified that is likely to exist or develop in other Glaser-Dirks Model DG–400 gliders of the same type design registered in the United States, the FAA is proposing AD action. The proposed AD would require replacing the propeller shaft, the bearings, and the front drive belt retaining rings with parts of improved design. Accomplishment of the proposed action would be in accordance with DG Flugzeugbau Technical Note No. 826/32, dated July 19, 1996, and DG Flugzeugbau WORKING INSTRUCTION No. 1 for TN 826/32, dated July, 1996.

Cost Impact

The FAA estimates that 35 gliders in the U.S. registry would be affected by the proposed AD, that it would take approximately 5 workhours per glider to accomplish the proposed action, and that the average labor rate is approximately $60 an hour. Parts cost approximately $460 per glider. Based on these figures, the total cost impact of the proposed AD on U.S. operators is estimated to be $266,000, or $760 per glider.

Proposed Compliance Time

The compliance time of the proposed AD is in calendar time instead of hours time-in-service (TIS). The average monthly usage of the affected glider ranges throughout the fleet. For example, one owner may operate the glider 25 hours TIS in one week, while another operator may operate the glider 25 hours TIS in one year. In order to ensure that all of the owners/operators of the affected glider have replaced the propeller shaft, bearings and front drive belt retaining rings within a reasonable amount of time, the FAA is proposing a compliance time of 4 calendar months.

Regulatory Impact

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

For the reasons discussed above, I certify that this action (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) 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 has been placed 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 a new airworthiness directive (AD) to read as follows:

Glaser-Dirks Flugzeugbau GMBH: Docket No. 98–CE–07–AD.

Applicability: Model DG–400 gliders, all serial numbers, certificated in any category.

Note 1: This AD applies to each glider 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 gliders 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 (c) 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 within the next 4 calendar months after the effective date of this AD, unless already accomplished.

To prevent failure of the propeller shaft, which could result in loss of glider propulsion during critical phases of flight, accomplish the following:

(a) Replace the propeller shaft, the bearings, and the front drive belt retaining rings with parts of improved design in

accordance with paragraph 2 of the Instructions section of DG Flugzeugbau Technical Note No. 826/32, dated July 19, 1996, and WORKING INSTRUCTION No. 1 for TN 826/32, dated July, 1996.

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

(c) An alternative method of compliance or adjustment of the compliance time that provides an equivalent level of safety may be approved by the Manager, Small Airplane Directorate, FAA, 1201 Walnut, suite 900, Kansas City, Missouri 64106. The request shall be forwarded through an appropriate FAA Maintenance Inspector, who may add comments and then send it to the Manager, Small Airplane Directorate.

Note 2: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Small Airplane Directorate.

(d) Questions or technical information related to DG Flugzeugbau Technical Note No. 826/32, dated July 19, 1996, and DG Flugzeugbau WORKING INSTRUCTION No. 1 for TN 826/32, dated July, 1996, should be directed to DG Flugzeugbau GmbH, P.O. Box 4120, 76625 Bruchsal, Germany; telephone: +49 7257–89–0; facsimile: +49 7257–8922. This service information may be examined at the FAA, Central Region, Office of the Regional Counsel, Room 1558, 601 E. 12th Street, Kansas City, Missouri 64106.

Note 3: The subject of this AD is addressed in German AD 96–243 DG–Flugzeugbau, dated August 29, 1996.

Issued in Kansas City, Missouri, on May 13, 1998.

Michael Gallagher,

Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. 98–13518 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–13–U

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. 97–CE–21–AD]

RIN 2120–AA64

Airworthiness Directives; Mitsubishi Heavy Industries, Ltd. Models MU–2B Series Airplanes

AGENCY: Federal Aviation Administration, DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This document proposes to adopt a new airworthiness directive (AD) that would apply to certain Mitsubishi Heavy Industries, Ltd. (Mitsubishi) MU–2B series airplanes. The proposed action would require incorporating several modifications to the operating systems and installing a placard with operating limitations within the pilot's clear view. Service history of the affected airplanes prompted the FAA to examine the design of these airplanes and analyze the ability of the pilots of these airplanes to fly and operate in icing conditions. The actions specified by the proposed AD are intended to prevent departure from controlled flight and to assist the pilot in detecting ice accumulation on the airplane when flying in icing conditions that exceed the airplane's ice protection capability, which could result in possible loss of control of the airplane.

DATES: Comments must be received on or before July 22, 1998.

ADDRESSES: Submit comments in triplicate to the Federal Aviation Administration (FAA), Central Region, Office of the Regional Counsel, Attention: Rules Docket No. 97–CE–21–AD, Room 1558, 601 E. 12th Street, Kansas City, Missouri 64106. Comments may be inspected at this location between 8 a.m. and 4 p.m., Monday through Friday, holidays excepted.

Service information that applies to the proposed AD may be obtained from Mitsubishi Heavy Industries America, Inc., 15303 Dallas Parkway, suite 685, LB–77, Dallas, Texas 75248; telephone (972) 980–5001; facsimile (972) 980–5091. This information also may be examined at the Rules Docket at the address above.

FOR FURTHER INFORMATION CONTACT: Mr. John Dow, Aerospace Engineer, Small Airplane Directorate, 1201 Walnut, suite 900, Kansas City, Missouri 64106, telephone (816) 426–6934; facsimile (816) 426–2169.

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 should 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 notice may be changed in light of the comments received.

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 that summarizes 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 notice must submit a self-addressed, stamped postcard on which the following statement is made: ''Comments to Docket No. 97–CE–21–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, Central Region, Office of the Regional Counsel, Attention: Rules Docket No. 97–CE–21–AD, Room 1558, 601 E. 12th Street, Kansas City, Missouri 64106.

Discussion

Service history of the Mitsubishi MU–2B series airplanes prompted the FAA to examine the design of these airplanes and analyze the ability of the pilots of these airplanes to fly and operate in icing conditions. The FAA recently conducted a special certification review (SCR) for the Mitsubishi MU–2B series airplanes. This examination shows that several accidents have occurred, and that future accidents/incidents may be prevented by modifications to the airplane design and by additional training to enhance the pilot's ability to manage the airplane in adverse operating conditions. The training issues were addressed in AD 97–20–14. Indications are that the pilot is not detecting or properly interpreting the visual cues of ice build-up on the airframe. The pilots of the airplanes involved in the accidents did not exit the icing conditions, but instead, relied on the autopilot to fly the airplane. In these accidents, the airplanes stalled while on autopilot, which resulted in departure from controlled flight into a spin or near vertical spiral until ground contact was made.

Explanation of Departure From Controlled Flight

Airplanes that fly in these severe icing conditions, although infrequently encountered, can accumulate ice formations that increase drag quickly and raise stall speeds significantly. Combining these elements with a loss of airspeed can cause aerodynamic flow separation or stall on one or both wings. This stall can result in an uncontrolled

rolling or pitching, especially if yawing is present at the stall. Heavy ice-induced stalls can occur very suddenly at airspeeds well in excess of normal stall speeds, with no artificial warning (stick shaker) or natural pre-stall buffet (stick shaker) to advise the pilot that the airplane is about to stall. If the pilot has put the airplane controls on autopilot, and takes no corrective actions during the ice induced slowdown, the autopilot then contributes to the departure from controlled flight.

The certification tests and operation of the MU–2B series airplanes reveal that these airplanes have the capability to cope with normal icing conditions. However, the FAA's current understanding of freezing rain and drizzle, known as supercooled large drops (SLD), shows that atmospheric icing conditions exist that exceed the capability of the pneumatic ice protection found on turbopropeller airplanes, including the MU–2B series airplanes. Flight into SLD, or freezing rain and freezing drizzle, can cause ice accretion on and beyond the active portion of the de-icing boots, on the upper and lower surfaces of the wing, as well as other unprotected surfaces of the airplane. The ice that forms beyond the boots cannot be removed. Ice increases drag, leading to decreased airspeed, and if level flight is maintained, increased angle-of-attack. This evolution can ultimately lead to aerodynamic flow separation over the wing, or stall. Ice can also form around the engine inlets. The accumulated ice might then loosen and be ingested into the engine, interrupt the airflow, and flame out the engine at a critical time.

Relevant Service Information

Mitsubishi has issued the following service bulletins which specify procedures that address the concerns in this proposed action.

- Test Instrumentation, Inc. Document No. MU2–1001, Rev. C., dated June 15, 1997, and Mitsubishi MU–2 Service Bulletin (SB) No. 231, dated July 2, 1997: these documents include procedures for incorporating an audible trim-in-motion alert system to notify the pilot that the trim is trimming nose-up while the autopilot is engaged;
- Test Instrumentation, Inc. Document No. MU2–5001, Rev. E., dated May 21, 1997, and Mitsubishi MU–2 SB No. 232, dated July 2, 1997: these documents include procedures for modifying the existing pneumatic de-icing system to assure that both wing and tailplane boots are receiving enough inflation pressure when the De-Ice System Annunciation is in the ''ON'' position, and circuit breaker modification is made;
- Mitsubishi MU–2 SB No. 217, Revision B, dated November 7, 1996 and Test Instrumentation Inc. Document No. MU2–6005, dated September 28, 1997: these documents include procedures for incorporating an ice detector system that includes an ice probe that will enunciate the presence of actual icing conditions.

The service bulletin specifies using a Rosemont ice detector, part number (P/N) 0871CT1, but this part may be substituted with Rosemont P/N 0871HL1/HL2 or an FAA-approved equivalent part number;

- Test Instrumentation, Inc. Document No. MU2–4001, Rev. C, dated June 30, 1997, and Mitsubishi MU–2 SB No. 231, dated July 2, 1997: these documents include procedures for incorporating an automatic autopilot disconnect system that turns off the autopilot when the airspeed of the airplane falls between 130 to 140 knots indicated airspeed (KIAS);
- Mitsubishi MU–2 SB No. 226B, Revision B, dated October 27, 1997: this document includes procedures for incorporating an auto-ignition (re-light) system; and
- Mitsubishi MU–2 SB No. 074/74–001, dated October 9, 1991: this document includes procedures for incorporating an engine ignition unit replacement (to increase the engines tolerance of ice) and reduce the chances of engine flame-out during critical phases of flight.

The FAA's Determination

After examining the circumstances and reviewing all available information related to the accidents described above, including the previously referenced service information, the FAA has determined that AD action should be taken. Taking AD action is needed to prevent departure from controlled flight and to assist the pilot in detecting ice accumulation on the airplane when flying in icing conditions that exceed the airplane's ice protection capability, which could result in possible loss of control of the airplane.

Explanation of the Provisions of the Proposed AD

Since an unsafe condition has been identified that is likely to exist or develop in other MU–2B series airplanes of the same type design, the proposed AD would require incorporating the following:

(1) An ice detection system,

(2) A de-ice monitoring system,

(3) An automatic autopilot disconnect system and a trim-in-motion alert system,

(4) An engine continuous-duty ignition unit replacement,

(5) An auto-ignition (re-light) system, and

(6) Fabricating a placard (using ⅛-inch letters) and installing this placard within the pilot's clear view with the following words:

Prior to the first flight of the each day, a negative torque sensing (NTS) check and a Propeller Feather Valve check must be performed in accordance with the Normal Checklist Procedures.

Proposed Compliance Time

The FAA has determined that the compliance time of the proposed AD should be specified in calendar time instead of hours time-in-service. Although the condition addressed by the proposed AD is unsafe while the airplane is in flight, the condition is not a result of repetitive airplane operation. The potential for the unsafe condition occurring is the same on the first flight as it is for subsequent flights. The proposed compliance time of ''12 calendar months after the effective date of this AD'' would not inadvertently ground airplanes and would assure that all owners/operators of the affected airplanes accomplish the proposed action in a reasonable time period.

Regulatory Flexibility Determination and Analysis

The Regulatory Flexibility Act of 1980 was enacted by Congress to assure that small entities are not unnecessarily or disproportionately burdened by government regulations. This Act establishes ''as principle of regulatory issuance that agencies shall endeavor, consistent with the objectives of the rule and of applicable statutes, to fit regulatory and informational requirements to the scale of the businesses, organizations, and governmental jurisdictions subject to regulation.'' To achieve this principle, the Act requires agencies to solicit and consider flexible regulatory proposals and to explain the rationale for their actions. The Act covers a wide range of small entities, including small businesses, not-for-profit organizations and small governmental jurisdictions.

Agencies must perform a review to determine whether a rule will have a ''significant economic impact on a substantial number of small entities.'' If the determination is that it will, the agency must prepare a Regulatory Flexibility Analysis as described in the Act. However, if after a review for a proposed or final rule, an agency

determines that a rule is not expected to have a significant economic impact on a substantial number of small entities, Section 605(b) of the Act provides that the head of the agency may so certify and a Regulatory Flexibility Analysis is not required. The Certification must include a statement providing the factual basis for this determination, and the reasoning should be clear.

The FAA has determined that this proposed AD would have a significant economic impact on a substantial number of small entities. After a review of alternatives, as required by Section 603(c) of the Act, the proposed AD is the least costly alternatives to improve the safety of the Mitsubishi MU–2B series airplanes that may encounter in-flight icing conditions.

The entities affected by this AD are believed to be mostly in Standard Industrial Classification (SIC) 4522, ''Air Transportation, Nonscheduled.'' Under the Small Business Administration (SBA), *Table of Size Standards*, March 1, 1996, an entity in SIC 4522 would be a small business if it has fewer than 1,500 employees.

The U.S. Registered Aircraft Database shows approximately 200 operators of Mitsubishi MU–2B series airplanes in the United States, but that only 13 entities operate two or more of these airplanes. Ownership of more than one MU–2B series airplane is believed to be limited to five percent of the affected aircraft owners. Only one of these operators had ten or more of these airplanes. The total number of owners operating of MU–2B series airplanes is in the range of 320 to 340, and the names of the owners suggest that the majority of these airplanes are operated by small entities. Consequently, this proposed AD is likely to affect a substantial number of small entities.

The initial cost for each owner/operator of an MU–2B series airplane is estimated to be approximately $25,728. Reported usage rates of 32 to 33 hours per month (almost 400 hours per year) indicate that an airplane would be subject to a total of four inspections per year. At a nominal inspection time of one hour per inspection and labor cost of $60 per hour, the proposed annual inspection costs would be approximately $240 per airplane. These estimates include costs for the associated record keeping. A reasonable range of costs arising from this proposed AD is suggested in the following table:

Cost of capital	Remaining life of aircraft	Annualized cost		Present value of total cost
		Initial	Total	
10%/year	20 years	$3,022	$3,262	$27,771
15%/year	20 years	4,110	4,350	27,230
10%/year	10 years	4,187	4,427	27,203
15%/year	10 years	5,126	5,366	26,933

The remaining life for an affected airplane will depend on the demand for the types of service provided (such as cargo delivery and medical evacuation), as well as the difference in cost between providing this service with the MU–2B series airplanes and the cost of using alternative aircraft or modes of transportation. According to the manufacturer, detailed inspections show that deterioration of the airframes has been quite small, so that a 20-year life expectancy may be a reasonable assumption. In addition, the manufacturer acknowledged recent instances of retired MU–2B series airplanes being returned to service. These considerations suggest that it is reasonable to assume a relatively long expected life for many of the MU–2B series airplanes, so that the annualized cost per affected aircraft may average less than $5,000.

With an average annual cost per airplane in the range of $3,200 to $5,400 (consistent with 10 to 20 years of remaining life and capital costs of 10 to 15 percent per year), the present value of the total cost would be approximately $27,000 per airplane. The total annualized cost of this proposed AD for the U.S. fleet would be in the range of $1 million (320×$3,200 = $1,024,000) to $1.8 million (340×$5,400 = $1,836,000). The present discounted value of total costs imposed by the proposed AD are in the range of $8.6 million to $9.4 million.

Market values for the affected airplanes are believed to be in the range of $300,000 to $800,000, depending on the airplane's age, condition, and installed equipment. Therefore, the proposed AD costs would be about 3.5 percent to 9 percent (($27,000/$800,000)×100% = 3.5% to ($27,000/$300,000) ×100% = 9%) of the market value of the airplane. Because the costs imposed by the proposed AD would be proportionately higher for less expensive airplanes, it is likely that they would also be proportionately higher for smaller, less financially strong operators than for larger operators.

Based on the above-referenced conditions, the proposed AD would have a substantial economic impact on a significant number of small entities.

Cost Versus Benefits

The purpose of the proposed AD is to improve flight safety under icing conditions for Mitsubishi MU–2B series airplanes. The National Transportation Safety Board (NTSB) Accident-Incident Database indicates that three Mitsubishi MU–2B airplane accidents occurred from 1982 through 1996, with a total of 14 fatalities. All three accidents were related to loss of control of the airplane while flying in severe icing conditions. These three airplane accidents amount to about one percent of the MU–2B series airplane fleet. All were part 91 operations.

In one of these accidents, involving eight fatalities in 1996, the pilot continued flight into (unforecast) severe icing conditions with known in-operative anti-ice gear. The NTSB report attributed the accident to flying with known equipment deficiencies and failure to maintain airspeed.

In a second accident, involving five fatalities in 1990, the NTSB noted that the probable cause included improper flight planning, which resulted in flight into icing conditions, along with failure to maintain adequate airspeed and control. Pilot inexperience in this Mitsubishi MU–2B series airplane was also cited as a related factor.

In a third accident involving one fatality in 1988, the pilot was the sole occupant. The pilot of the 1988 accident reported an uncontrolled descent shortly after starting to climb, following a descent that had been made in order to remove structural icing. Although the reason for this accident was indicated to be undetermined, the airplane was believed to have had problems with cabin pressurization, as well as some structural damage associated with landing in an overweight condition, prior to encountering the icing. Crew error was found to be one of the causes of the first two accidents, and seems

likely in the third accident. Timely warnings of the ice forming on the airframe may have prevented some or all of these accidents.

In developing this Regulatory Flexibility Analysis several alternatives to proposing this AD were considered. The alternatives included: (1) taking no action, including issuance of the proposed AD, (2) requiring additional training and the provision of special instructions relating to operating in icing conditions for MU–2B series pilots, (3) banning the MU–2B series airplanes from flights into known or suspected icing conditions, and (4) issuing the proposed AD.

Alternative (1): taking no action. Taking no action would permit the continuation of current conditions that could result in a repeat of icing-related accidents similar to those that have occurred over the past 10 years.

Alternative (2): requiring additional training. A requirement for additional training is addressed in AD 97–20–14, Amendment 39–10150 (62 FR 51594) issued on September 26, 1997, which requires periodic training of pilots and crew flying any Mitsubishi MU–2 series airplane into possible or forecast icing conditions. This training should assist in reducing future ice-related accidents for the affected airplanes.

Alternative (3): banning flight into known or suspected icing conditions. Banning flight into known or suspected icing conditions would not eliminate inadvertent encounters with icing conditions aloft. Such restrictions may have little effect flying into unforecast icing conditions with inoperable anti-ice equipment and insufficient flight planning. Unknown forecast conditions aloft and insufficient flight planning contributed to two of the accidents (and 13 of the 14 fatalities) cited. In addition, such a ban would impose costs on owners/operators in the form of significant losses in value for the airplanes, since the airplanes would be prevented from making flights, despite being outfitted with anti-ice equipment.

Alternative (4): issuing the proposed AD. Issuing the proposed AD would result in the installation of equipment that would provide a timely warning at the onset of icing conditions, so that most accidents resulting from inadvertent encounters with severe icing conditions could possibly be prevented.

A benefit/cost comparison for this proposed AD can be made by noting that the present value of the costs imposed by this rule are on the order of $9 million. The present value of a single life saved sometime over the next 20 years (making use of the Department of Transportation's value for an avoided fatality of $2.7 million) is approximately $1.43 million. This figure reflects 1/20 of an annual avoided fatality ($2.7 million / 20 = $135,000) discounted over 20 years at the Office of Management and Budget-specified discount rate of 7 percent.

With these figures in mind, the proposed AD would have benefits in excess of costs if it were to result in the avoidance of a single accident that involves 6 or 7 fatalities ($9 million / $1.43 million = 6.29 avoided fatalities) over the next 20 years. Adding the benefit of avoiding the loss of an airplane worth nearly a half million dollars to the benefit presented above increases the benefits relative to costs related to the proposed actions.

Although it may be assumed that current operators of these airplanes are now aware of the dangers posed by icing conditions, so that icing-related accidents are now less likely than in the recent past, the avoidance of 6 or 7 icing-related fatalities over the next 20 years is not implausible. These airplanes can carry up to 12 passengers and crewmembers. The past 10 years' experience implies an annual icing-related accident rate of 0.33 (3/10 = 0.33) with an annual icing-related fatality rate of 1.4 (14/10 = 1.4). Seven avoided fatalities over the next 20 years implies an annual avoided fatality rate of 0.35 (7/20 = 0.35), or one-fourth of the average Mitsubishi MU–2B airplane icing-related fatality rate observed over the past 10 years.

For reasons outlined above, the FAA has determined that the proposed AD is likely to have benefits in excess of costs and is not aware of a less costly alternative that would be likely to bring about a significant improvement in the safety of Mitsubishi MU–2B series airplanes that encounter in-flight icing conditions.

Regulatory Impact

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

For the reasons discussed above, I certify that this action (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) if promulgated, will 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 has been placed 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 USC 106(g), 40113, 44701.

§ 39.13 [Amended]

2. Section 39.13 is amended by adding a new airworthiness directive (AD) to read as follows:

Mitsubishi Heavy Industries, Ltd.: Docket No. 97–CE–21–AD.

Applicability: Models MU–2B, MU–2B–10, MU–2B–15, MU–2B–20, MU–2B–25, MU–2B–26, MU–2B–26A, MU–2B–30, MU–2B–35, MU–2B–36, MU–2B–36A, MU–2B–40, and MU–2B–60 airplanes (all serial numbers), certificated in any category.

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 (i) 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 within the next 12 calendar months after the effective date of this AD, unless already accomplished.

To prevent departure from controlled flight and to assist the pilot in detecting ice accumulation on the airplane when flying in icing conditions that exceed the airplane's ice protection capability, which could result in possible loss of control of the airplane, accomplish the following:

(a) Incorporate an ice detection system in accordance with the instructions in Mitsubishi MU–2 Service Bulletin (SB) No. 217, Revision B, dated November 7, 1996, and Test Instrumentation Inc. Document No. MU2–6005, dated September 28, 1997.

Note 2: The Rosemount ice detection probe (part number (P/N) 0871 HL1/HL2 or an FAA-approved equivalent part number) may be substituted for the Rosemount P/N 0871CT1 called out in Mitsubishi MU–2B SB No. 217, Revision B, dated November 7, 1996, and Test Instrumentation Inc. Document No. MU2–6005, dated September 28, 1997.

(b) Incorporate a pneumatic de-ice monitoring system in accordance with the instructions in Test Instrumentation, Inc. Document No. MU2–5001, Rev. E., dated May 21, 1997, and Mitsubishi MU–2 SB No. 232, dated July 2, 1997.

(c) Incorporate a trim-in-motion alerting system and an automatic autopilot disconnect system in accordance with the instructions in Test Instrumentation, Inc. Document No. MU2–1001, Rev. C, dated June 15, 1997, Test Instrumentation, Inc. Document No. MU2–4001, Rev. C, dated June 30, 1997, and Mitsubishi MU–2 SB No. 231, dated July 2, 1997.

(d) Incorporate an engine ignition unit replacement in accordance with the instructions in Mitsubishi MU–2B SB No. 074/74–001, dated October 9, 1991.

(e) Incorporate an auto-ignition (re-light) system in accordance with the instructions in Mitsubishi MU–2 SB No. 226B, Revision B, dated October 27, 1997.

(f) Fabricate a placard with the following words and install this placard within the pilot's clear view:

Prior to the first flight of the day, a negative torque sensing (NTS) check and a Propeller Feather Valve check must be performed in accordance with the Normal Checklist Procedures.

(g) Paragraph (f) of this AD can be accomplished by the owner/operator holding at least a private pilot certificate as authorized by section 43.7 of the Federal Aviation Regulations (14 CFR 43.7), and must be entered into the aircraft records showing compliance with this AD in accordance with section 43.9 of the Federal Aviation Regulations (14 CFR 43.9).

(h) Special flight permits may be issued in accordance with sections 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.

(i) An alternative method of compliance or adjustment of the compliance time that provides an equivalent level of safety may be approved by the Manager, Small Airplane Directorate, 1201 Walnut, suite 900, Kansas City, Missouri 64106. The request shall be forwarded through an appropriate FAA Maintenance Inspector, who may add comments and then send it to the Manager, Small Airplane Directorate.

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

(j) All persons affected by this directive may obtain copies of the documents referred to herein upon request to Mitsubishi Heavy Industries America, Inc., 15303 Dallas Parkway, suite 685, LB–77, Dallas, Texas; or may examine these documents at the FAA, Central Region, Office of the Regional Counsel, Room 1558, 601 E. 12th Street, Kansas City, Missouri 64106.

Issued in Kansas City, Missouri, on May 13, 1998.

Michael Gallagher,

Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. 98–13517 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–13–U

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Parts 91 and 150

[Docket No. 2923]

Compatible Land Use Planning Initiative

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Request for comments.

SUMMARY: The FAA is seeking new ideas regarding how the agency can better influence land use decisions around airports. Noise contours around airports will continue to shrink with the elimination of noisier Stage 2 airplanes by the year 2000. The FAA now seeks to develop a process that will better influence long-term land use planning and zoning around airports. This notice solicits suggestions about methods the FAA can use to encourage and help State and local governments achieve and maintain land use compatibility around airports.

DATES: Comments must be received on or before June 22, 1998.

ADDRESSES: Comments should be mailed in triplicate to: Federal Aviation Administration, Office of the Chief Counsel, Attention: Rules Docket (AGC–200), Docket No. 29231, 800 Independence Avenue, SW., Washington, DC 20591. Comments may also be sent electronically to the Rules Docket by using the following Internet address: 9-nprm-cmts@faa.dot.gov. Comments must be marked Docket No. 29231. Comments may be examined in the Rules Docket in Room 915G on weekdays between 8:30 a.m. and 5:00 p.m., except on Federal holidays.

FOR FURTHER INFORMATION CONTACT: Alan Trickey, Policy and Regulatory Division, AEE–300, Federal Aviation Administration, 800 Independence Avenue, SW., Washington, DC 20591; telephone, (202) 267–3496; facsimile, (202) 267–5594; email, alan.trickey@faa.dot.gov.

SUPPLEMENTARY INFORMATION:

Background

Aircraft noise is a serious problem for communities around airports. Federal, state and local governments have spent several billion dollars for the acquisition of land, soundproofing, changes in airport operations and airspace, and processing of complaints. The airline industry has expended billions more to acquire quieter aircraft that reduce noise exposure levels. Although this collective effort has resulted in significant progress, additional measures are needed to maintain current gains and prevent the development of new noncompatible land uses around airports.

The FAA has been actively engaged in measures to solve the problem of aircraft noise since the 1960's. Specifically, the FAA has issued regulations phasing out noisier airplanes. The noisiest Stage 1 airplanes were phased out of commercial operations in the United States by 1988. The current phaseout will eliminate large Stage 2 airplanes from operations in the contiguous United States by the year 2000. The FAA provides grants to airport operators willing to undertake noise abatement measures such as the purchase of land and soundproofing of residences.

Based on several studies, the FAA expects noise contours at most airports to continue to shrink for several years into the 21st century due to the elimination of noisier aircraft. After the completion of the Stage 2 phaseout by the year 2000, the FAA anticipates that these contours could begin to expand again at some airports primarily due to increases in operations. It is essential for local jurisdictions to plan ahead to maintain the land use compatibility already achieved near airports and to control land uses to prevent new noise-sensitive development within an agreed upon protection zone.

The U.S. Constitution, gives individual States the authority over land use, though such authority is often delegated to local governments. Some airports are operated by the state or municipal governments that have the power to achieve appropriate land use controls through zoning and other authorities. But even when governmental bodies are themselves airport operators, the noise effects of their airports often occur in areas outside their jurisdictions. Land use decisions generally reflect the needs of the community, which include but are

not limited to considerations of aviation noise.

The FAA is charged with the responsibility to maintain a safe and efficient national airspace system. The FAA fosters compatible land use planning both to facilitate access to airports commensurate with the demands of air commerce and to abate the aviation noise effects in the airport vicinity. Even though the Federal government lacks the authority to zone land, the FAA may use its influence to encourage compatible land use in the vicinity of an airport. The agency exerts this influence through airport development grant agreements, environmental review requirements, grants for airport noise compatibility planning, and educational instruments on compatible land use planning. The FAA has issued guidelines for land use compatibility around airports to assist those responsible for determining land use. These guidelines are primarily contained in 14 CFR Part 150 and related guidance.

In January 1995, an FAA-sponsored Study Group on Compatible land Use, which was composed of community, airport, and aviation representatives, produced a report with recommendations for Federal initiatives to promote compatible land use planning and controls around airports. The group's recommendations included the following concepts:

- Provide direct Federal funding through the Airport Improvement Program (AIP) to non-airport sponsors who have land use planning jurisdiction;
- Encourage cooperative agreements between airport sponsors and communities;
- Revise FAA regulations in Part 150 or supporting guidelines to recognize and publicize successful land use compatibility concepts, encourage more effective public participation and encourage innovative land-use control techniques;
- Strengthen the linkage between Part 150 noise compatibility programs and existing Federal programs that reinforce land use planning, such as Federal Housing Administration and Department of Veterans Affairs policies not to accept properties in high-noise areas for mortgage insurance.

The FAA has implemented portions of these recommendations. These ideas are presented here only to stimulate thought for addition ideas.

Request for Comments

The FAA is soliciting comments on any concepts that might serve to promote compatible land use planning by state and local authorities and to discourage development of noncompatible land uses around airports. The FAA is particularly interested in bold, innovative, and creative options that could be implemented quickly to discourage development of noncompatible land uses, as well as long-term solutions. Comments that provide a factual basis for the suggestions are particularly helpful. The more specific the suggestions for FAA action, the better. Ultimately, any process should achieve long-term cost avoidance for all levels of government.

The FAA will review information from public comments and other sources to identify methods that might assist State and local governments in achieving and maintaining land use compatibility around airports.Further action would depend on the nature and scope of the methods identified.

Communications should identify the notice docket number and be submitted in triplicate using one of the media specified in the **ADDRESSES** paragraph above. All communications will be filed in the docket. The docket is available for public inspection both before and after the closing date for receipt of comments.

The FAA will acknowledge receipt of a comment if the commenter includes a self-addressed, stamped postcard with the comment. The postcard should be marked ''Comments to Docket No. [29231].'' When the comment is received by the FAA, the postcard will be dated, time stamped, and returned to the commenter.

Issued in Washington, D.C. on May 15, 1998.

James D. Erickson,

Director of Environment and Energy.

[FR Doc. 98–13577 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–13–M

CONSUMER PRODUCT SAFETY COMMISSION

16 CFR Parts 1615 and 1616

Proposed Technical Changes; Standard for the Flammability of Children's Sleepwear: Sizes 0 Through 6X; Standard for the Flammability of Children's Sleepwear: Sizes 7 Through 14

AGENCY: Consumer Product Safety Commission.

ACTION: Proposed technical changes.

SUMMARY: The Commission proposes to amend the flammability standards for children's sleepwear in sizes 0 through 6X and 7 through 14 to make several technical changes that would correct the definition of ''tight-fitting garment.'' [1] The proposed changes will clarify the points where garment measurements should be made.

DATES: Written comments concerning this proposed amendment are due no later than August 4, 1998.

ADDRESSES: Comments should be mailed to the Office of the Secretary, Consumer Product Safety Commission, Washington, D.C. 20207, telephone: (301) 504–0800 or delivered to the Office of the Secretary, room 501, 4330 East-West Highway, Bethesda, Maryland 20814. Comments should be submitted in five copies and captioned ''Sleepwear.'' Comments may also be filed by telefacsimile to (301) 504–0127 or by email to cpsc-os@cpsc.gov

FOR FURTHER INFORMATION CONTACT: Margaret Neily, Project Manager, Directorate for Engineering Sciences, Consumer Product Safety Commission, Washington, D.C. 20207; telephone (301) 504–0550, extension 2354.

SUPPLEMENTARY INFORMATION:

A. Background

In 1971, the Secretary of Commerce issued a flammability standard for children's sleepwear in sizes 0 through 6X, which became effective in 1972. That standard, issued under Section 4 of the Flammable Fabrics Act (''FFA''), 15 U.S.C. 1193, prescribes tests for children's sleepwear garments and fabrics intended for use in children's sleepwear. The flammability standard for children's sleepwear in sizes 0 through 6X is codified at 16 CFR Part 1615.

In 1973, responsibility for administration and enforcement of the FFA was transferred to the Consumer Product Safety Commission by provisions of section 30(b) of the Consumer Product Safety Act. 15 U.S.C. 2079(b). In 1974, the Commission issued a flammability standard for children's sleepwear in sizes 7 through 14, to become effective in 1975. The tests in that standard are substantially the same as those in the standard for children's sleepwear in sizes 0 through 6X. The flammability standard for children's sleepwear in sizes 7 through 14 is codified at 16 CFR Part 1616.

Both standards require that test specimens must self-extinguish when exposed to a small open-flame ignition source. Self-extinguishing fabrics and garments are those that stop burning when removed from an ignition source.

[1] The Commission voted to issue the proposed changes 2–0. Commissioners Mary Gall and Thomas Moore voted in favor of issuing the proposed rule. Chairman Ann Brown abstained.

Both standards require manufacturers of sleepwear garments to perform prototype tests on specimens of fabric, seams, and trim with acceptable results before beginning production of sleepwear garments. Both standards also require manufacturers of sleepwear fabrics and garments to group fabrics and garments into production units and to randomly sample and test products from each production unit. Neither standard requires that specific fabrics or flame-retardant treatments be used in the manufacture of children's sleepwear.

On September 9, 1996, the Commission issued a final rule amending the flammability standards for children's sleepwear to exclude from the definition of ''children's sleepwear'' (1) garments sized for infants nine months of age or younger and (2) tight-fitting sleepwear garments for children older than nine months. 61 FR 47634.

The Commission found that such tight-fitting sleepwear did not present an unreasonable risk of injury. Rather, the Commission's information showed that sleepwear incidents occurred with loose-fitting garments such as nightgowns. A review of literature for that amendment showed that fit can influence garment flammability. Garments that fit close to the body are less likely to catch fire in the first place and less likely to allow heat to develop between the fabric and the body, thus decreasing the likelihood of thermal injury. *Id.* The Commission concluded that garments fitting closely and that touch the body at key points should be exempt from the sleepwear standards as they do not present the same risk as loose-fitting garments. These amendments became effective on January 1, 1997. However, the Commission also issued a stay of enforcement for close-fitting garments which are labeled and promoted as underwear. That stay expires on June 1, 1998. 62 FR 60163.

The Commission defined tight-fitting garments as those that did not exceed certain measurements in the chest, waist, seat, upper arm, thigh, wrist, and ankle for each size ranging from over 9 months through children's size 14. In the amendments, the Commission specified maximum allowable measurements for each of these locations for each size garment. 61 FR 47644–47.

B. Statutory Provisions

The FFA provides that the Commission can issue or amend a flammability standard when the standard may be needed to protect the public from an unreasonable risk of the occurrence of fire leading to death, injury or significant property damage. 15 U.S.C. 1193(a).

Section 4(g) of the FFA, states that a proceeding ''for the promulgation of a regulation under this section'' shall be initiated by publication of an advance notice of proposed rulemaking (''ANPR''). 15 U.S.C. 1193(g). That section requires that the ANPR identify the product and the nature of the risk at issue; summarize the alternatives under consideration; provide information about existing relevant standards; and invite interested persons to submit comments on the ANPR. *Id.*

Due to the technical nature and narrow scope of this proceeding, an ANPR conforming to the requirements of section 4(g) would be of no value to the public or the Commission. This proposed amendment would simply correct errors in the previous amendments to the children's sleepwear standards. The only change that would result if this amendment were to be issued in final is that some locations on sleepwear garments would be measured in a slightly different place to determine whether they could be exempt as tight-fitting garments. Thus, the Commission is initiating this rulemaking with this notice of proposed rulemaking (''NPR'') rather than an ANPR.

C. Proposed Amendments

1. Need for Technical Changes

Once manufacturers began to design tight-fitting sleepwear that would meet the amendments, they identified some problems with design and construction of these garments. First, in December 1996, it became apparent that the location specified to measure the upper arm (''at a line perpendicular to the sleeve. Extending from the outer edge of the sleeve to the arm pit'') would result in an unworkable garment. Some garment manufacturers asserted that measuring the upper arm at this location could result in an opening at the upper end of the sleeve (the armhole) that would be uncomfortable to the wearer. Thus, the Commission staff sent an enforcement letter to industry clarifying the measurement point for the upper arm.

Industry members told CPSC staff of other manufacturing problems they were having with making tight-fitting sleepwear. On June 4, 1997, an industry task force presented the staff with recommendations for producing cotton garments. They suggested a new set of garment dimensions as well as revised points of measurements. Most dimensions were larger than those in the Commission's standard. The staff reviewed the suggestions from the industry task force and those of other industry members. The staff concluded that some technical changes to the standard were necessary for manufacturers to make workable garments. However, the staff concluded that most of the changes advocated by the industry task force and others would result in larger garments that would not meet the standard's safety criteria. As mentioned above, the Commission based its exemption for tight-fitting garments on information showing that garments close to the body and touching it at key points would not present an unreasonable risk. The revisions suggested by industry would produce garments that would fall away from the body.

It seemed apparent to the staff that some adjustments needed to be made to the locations for measurements specified in the amendments for some points on the garments. The staff believed that these adjustments would be needed for the point of measurement of the upper arm, the seat, and the thigh. The staff also examined possible changes to the sweep (bottom of the top of a two-piece garment). In order to better assess this need and to determine if the possible changes would result in practical, wearable garments, the staff conducted structured observations of some garments.

2. Observations

The staff conducted a series of observations to see if the technical changes that appeared necessary would result in practical garments. The staff considered practical garments to be ones that adhere to the intentions of the regulation to provide a snug fit while permitting the wearer to move without undue discomfort or restraint. Eight manufacturers provided garments for children to try on so that the staff could assess the comfort and fit of the various garments. Numerous different fabrics were used (several 1x1 rib knits, several interlock knits, and a thermal knit). Garment fit was evaluated by CPSC staff with experience in garment design and construction. During the observations children put on and took off the garments, played actively and simulated sleeping. The staff observers looked for indications that the garments were binding or causing discomfort. The children also took garments home to sleep in.

One garment that met the current tight-fitting requirements was included. It proved to be impractical for several reasons. Measuring the upper arm from the arm pit produced an armhole too small to be comfortable and made it

impossible for a child to remove the garment top without assistance. The points of measurement for the thigh and seat resulted in pants that were unnecessarily tight in these areas. This tightness would also tend to further restrict the fabrics that could be used.

The garments made according to measurement locations contemplated by the staff appeared to be wearable, comfortable and suitable for sleeping and play. Children (or parents of smaller children) had no problems putting the garments on or removing them. The children's bodies remained covered when they moved about. The fabrics' stretch accommodated leg and arm movements so the children were able to bend, squat, run and roll. The children reported no discomfort sleeping in the garments overnight.

3. Substance of Changes

Measurement of Upper Arm

As explained above, this proposed amendment would allow manufacturers to measure sleepwear garments at a location that better approximates the true upper arm of the garment. In an effort to simplify the definition of ''tight-fitting garment'' the 1996 sleepwear amendments called for measuring from the arm pit; however, this does not allow sufficient room at the upper opening of the sleeve. Under the proposed correction, the upper arm would be measured from the shoulder to approximately one quarter the length of the arm.

The maximum upper arm dimensions for each size specified in the 1996 sleepwear amendments would remain unchanged. These are indicated in the charts provided in the September 9, 1996 **Federal Register** notice. 61 FR 47644–47 (codified at 16 CFR 1615.1(o) and 1616.2(m)). This proposed amendment would only change the location where the upper arm is measured.

To determine the appropriate point for the upper arm measurement, the staff considered available sizing and body measurements. For sizes 9 months through 6x the staff based its calculations on the arm lengths given in ASTM standards D4910–95a and D5826–95. Currently there is no ASTM standard for body measurements for sizes 7 through 14. Therefore the staff based its calculations for these sizes on the 1977 anthropometric study of U.S. children conducted by the University of Michigan.

Measurement of Seat

The 1996 sleepwear amendments state that the seat should be measured ''at widest location between waist and crotch.'' 16 CFR 1615.1(o) and 1616.2(m) (see footnotes to chart). If read literally, this describes a location immediately above the bottom of the crotch and is essentially the same location as specified for the thigh measurement. This is not where the seat/hip measurement is normally made under general industry practices. A literal reading of this direction results in a more contstricted pant in the seat and thigh area.

Originally, the staff considered measuring just above the curve in the crotch seam, some specified number of inches above the bottom of the crotch. A different distance would be specified for groups of sizes, e.g., 2½ inches above the bottom of the crotch for infant sizes.

However, during the observations the staff found that specifying the point of measurement as 4 inches above the crotch consistently matched the seat/hip location on the wearer. Specifying a uniform measurement for all sizes also has the advantage of being easier to apply both for manufacturers and for Commission enforcement. Thus, the Commission proposes to specify that the seat should be measured 4 inches above the crotch for all sizes.

Measurement of Thigh

The amendments state that the thigh measurement should be taken ''at a line perpendicular to the leg extending from the outer edge of the leg to the crotch.'' 16 CFR 1615.1(o) and 1616.2(m)(see footnotes to chart). This calls for measuring the thigh right at the bottom of the crotch. This is not really the location of the thigh and means measuring at a point where bulky seams join. Typical practice in the garment design and manufacturing industry is to measure the thigh at a point one inch down the inseam from its intersection with the crotch seam. This provides a more accurate measurement of the thigh without interference from the bulky intersection of the seams. Thus, the Commission proposes that the thigh be measured at this point.

Sweep

The staff also considered whether any change should be made to the sweep of the top of a two-piece garment. The existing standard provides that the sweep must be equal to or less than the waist dimension. This is specified in the notes to the chart specifying where to measure the waist (''on two-piece garment, measure width at the bottom of the upper piece, and the top of the lower piece.''). The staff considered also allowing an hourglass silhouette that essentially is allowed now for one-piece garments. However, the observations showed that such an hourglass shape for a two-piece garment could create extra loose fabric around the waist after a child has raised her arms. That is, after a child is moving around the top would ride up to the waist creating loose fabric. Thus, the Commission is not proposing to make any changes to the sweep of the garments.

D. Effective Date

Section 4(b) of the FFA provides that an amendment of a flammability standard shall become effective one year from the date it is promulgated, unless the Commission finds for good cause that an earlier or later effective date is in the public interest and publishes that finding. 15 U.S.C. 1193(b). Section 4(b) also requires that an amendment of a flammability standard shall exempt product ''in inventory or with the trade'' on the date the amendment becomes effective, unless the Commission limits or withdraws that exemption because those products are so highly flammable that they are dangerous for use by consumers.

The Commission has reason to believe that an effective date 30 days after publication of final amendments will be in the public interest. This would provide adequate notice to the public and would allow for the prompt initiation of these minor adjustments.

The Commission does not propose to withdraw or limit the exemption for products in inventory or with the trade as provided by section 4(b) of the FFA. The Commission notes that on December 9, 1996 the Commission staff issued an enforcement policy stating that it would exercise its enforcement discretion concerning the measurement of the upper arm between the shoulder and the elbow. Specific measurement points for each size were given in a table. Thus, manufacturers may currently use the table reproduced below in the proposed amendments when measuring the sleepwear garment's upper arm. The other proposed technical changes are also minor in nature, simply changing the point of measurement. Thus, the Commission believes that a 30-day effective date once the changes have been issued as a final rule is appropriate. Manufacturers who wish to may use the proposed points of measurement in making garments, and the staff will not take any enforcement action. Of course, manufacturers may also continue to use the points of measurement specified in the 1996 amendments until any changes become effective.

E. Impact on Small Businesses

When an agency undertakes a rulemaking proceeding, the Regulatory Flexibility Act, 5 U.S.C. 601 *et seq.*, generally requires the agency to prepare proposed and final regulatory flexibility analyses describing the impact of the rule on small businesses and other small entities. Section 605 of the Act provides that an agency is not required to prepare a regulatory flexibility analysis if the head of an agency certifies that the rule will not have a significant economic impact on a substantial number of small entities.

The Commission hereby certifies that the proposed amendments to the flammability standards for children's sleepwear described below will not have a significant impact on a substantial number of small businesses or other small entities. The proposed amendments clarify where the upper arm, seat and thigh measurements should be taken to determine whether a children's sleepwear garment may be exempt as a ''tight-fitting garment.'' These changes in the location of measurement will not have an impact on small businesses.

F. Environmental Considerations

Pursuant to the National Environmental Policy Act, and in accordance with the Council on Environmental Quality regulations and CPSC procedures for environmental review, the Commission has assessed the possible environmental effects associated with the proposed amendments to the children's sleepwear standards.

The Commission's regulations state that amendments such as this one normally have little or no potential for affecting the human environment. 16 CFR 1021.5(c)(3). The Commission has no information indicating that this particular amendment would affect the environment. Therefore, the Commission determines that neither an environmental assessment nor an environmental impact statement is required.

G. Executive Orders

According to Executive Order 12988 (February 5, 1996), agencies must state in clear language the preemptive effect, if any, of new regulations. These amendments, if issued in final, would slightly modify the flammability standards for children's sleepwear under the FFA. The FFA provides that, generally, when a flammability standard issued under the FFA is in effect, ''no State or political subdivision of a State may establish or continue in effect a flammability standard or other regulation for such fabric, related material, or product if the standard or other regulation is designed to protect against the same risk of occurrence of fire'' as the FFA standard ''unless the State or political subdivision standard or other regulation is identical'' to the FFA standard. 15 U.S.C. 1203(a). A local standard may be excepted from this preemptive effect if: (1) the local standard provides a higher degree of protection from the risk of occurrence of fire than the FFA standard or (2) the State or political subdivision applies to the Commission for an exemption from the FFA's preemption clause and the Commission grants the exemption through a process specified at 16 CFR part 1061. 15 U.S.C. 1203(b) and (c).

Thus, the proposed amendments would modify the points specified for measuring garments exempt from the sleepwear flammability standards that preempt non-identical state or local flammability standards or regulations which are designed to protect against the same risk of occurrence of fire as the FFA flammability standards for children's sleepwear.

In accordance with Executive Order 12612 of October 26, 1987, the Commission certifies that the proposed amendments do not have sufficient implications for federalism to warrant a Federalism Assessment.

List of Subjects in 16 CFR Parts 1615 and 1616

Clothing, Consumer protection, Flammable materials, Infants and children, Labeling, Records, Sleepwear, Textiles, Warranties.

Conclusion

For the reasons stated above and pursuant to the authority of section 4 of the Flammable Fabrics Act (15 U.S.C. 1193) the Commission proposes to amend 16 CFR parts 1615 and 1616 as follows:

PART 1615—STANDARD FOR THE FLAMMABILITY OF CHILDREN'S SLEEPWEAR: SIZES 0 THROUGH 6X

1. The authority citation for part 1615 continues to read as follows:

Authority: Sec. 4, 67 Stat. 112, as amended, 81 Stat. 569–70; 15 U.S.C. 1193.

2. Section 1615.1 is amended by revising paragraph (o) introductory text and (o)(1) to read as follows:

§ 1615.1 Definitions.

* * * * *

(o) *Tight-fitting garment* means a garment which:

(1)(i) In each of the sizes listed below does not exceed the maximum dimension specified below for the chest, waist, seat, upper arm, thigh, wrist, or ankle:

	Chest	Waist	Seat	Upper arm	Thigh	Wrist	Ankle
Size 9–12 mos							
Maximum Dimension:							
Centimeters	48.3	48.3	48.3	14.3	26.7	10.5	13
(inches)	(19)	(19)	(19)	(5⅝)	(10½)	(4⅛)	(5⅛)
Size 12–18 mos							
Maximum Dimension:							
Centimeters	49.5	49.5	50.8	14.9	28.3	10.5	13.1
(inches)	(19½)	(19½)	(20)	(5⅞)	(11⅛)	(4⅛)	(5⅛)
Size 18–24 mos							
Maximum Dimension:							
Centimeters	52.1	50.8	53.3	15.6	29.5	11	13.6
(inches)	(20½)	(20)	(21)	(6⅛)	(11⅝)	(4¼)	(5⅜)

	Chest	Waist	Seat	Upper arm	Thigh	Wrist	Ankle
Size 2							
Maximum Dimension:							
Centimeters	52.1	50.8	53.3	15.6	29.8	11.4	14
(inches)	(20½)	(20)	(21)	(6⅛)	(11¾)	(4½)	(5½)
Size 3							
Maximum Dimension:							
Centimeters	53.3	52.1	56	16.2	31.4	11.7	14.9
(inches)	(21)	(20½)	(22)	(6⅜)	(12⅜)	(4⅝)	(5⅞)
Size 4							
Maximum Dimension:							
Centimeters	56	53.3	58.4	16.8	33.0	12.1	15.9
(inches)	(22)	(21)	(23)	(6⅝)	(13)	(4¾)	(6¼)
Size 5							
Maximum Dimension:							
Centimeters	58.4	54.6	61.0	17.5	34.6	12.4	16.8
(inches)	(23)	(21½)	(24)	6⅞)	13⅝)	(4⅞)	(6⅝)
Size 6							
Maximum Dimension:							
Centimeters	61.0	55.9	63.5	18.1	36.2	12.7	17.8
(inches)	(24)	(22)	(25)	(7⅛)	(14¼)	(5)	(7)
Size 6X							
Maximum Dimension:							
Centimeters	62.9	57.2	65.4	18.7	37.8	13.0	18.7
(inches)	(24¾)	(22½)	(25¾)	(7⅜)	(14⅞)	(5⅛)	(7⅜)

Note: Measure the dimensions on the front of the garment. Lay garment, right side out, on a flat, horizontal surface. Smooth out wrinkles. Measure distances as specified below and multiply them by two. Measurements should be equal to or less than the maximum dimensions given in the standards.

(A) Chest—measure distance from arm pit to arm pit (A to B) as in Diagram 1.

(B) Waist—See Diagram 1. *One-piece garment,* measure at the narrowest location between arm pits and crotch (C to D). *Two-piece garment,* measure width at both the bottom/ sweep of the upper piece (C to D) and, as in Diagram 3, the top of the lower piece (C to D).

(C) Wrist—measure the width of the end of the sleeve (E to F), if intended to extend to the wrist, as in Diagram 1.

(D) Upper arm—draw a straight line from waist/sweep D through arm pit B to G. Measure down the sleeve fold from G to H. Refer to table below for G to H distances for each size. Measure the upper arm of the garment (perpendicular to the fold) from H to I as shown in Diagram 1.

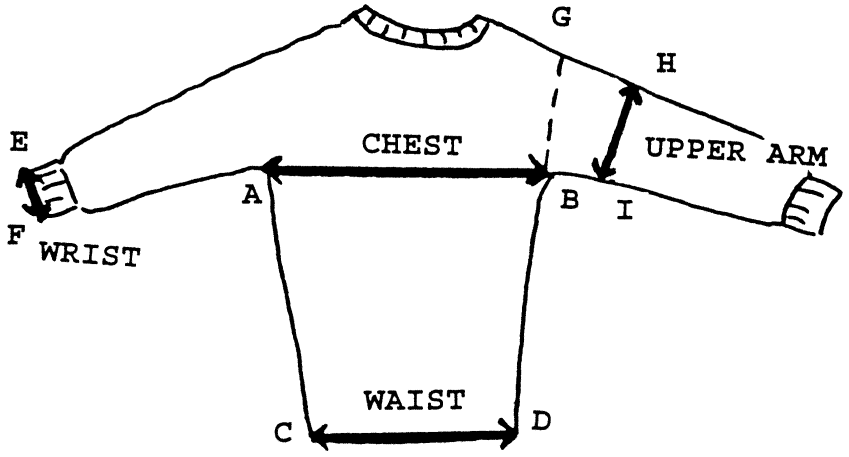


Diagram 1

DISTANCE FROM SHOULDER (G) TO (H) FOR UPPER ARM MEASUREMENT FOR SIZES 9 MONTHS THROUGH 6X

9–12 mo	12–18 mo	18–24 mo	2	3	4	5	6	6x
5.8 cm 2⅛″	6.6 cm 2⅝″	7.4 cm 2⅞″	7.4 cm 2⅞″	8.1 cm 3¼″	8.8 cm 3½″	9.5 cm 3¾″	10.3 cm 4″	11 cm 4⅜″

(E) Seat—Fold the front of the pant in half to find the bottom of the crotch at J as in the left side of Diagram 2. The crotch seam and inseam intersect at J. Mark point K on the crotch seam at 4 inches above and perpendicular to the bottom of the crotch. Unfold the garment as in the right side of Diagram 2. Measure the seat from L to M through K as shown.

(F) Thigh—measure from the bottom of the crotch (J) 1 inch down the inseam to N as in the left side of Diagram 2. Unfold the garment and measure the thigh from the inseam at N to O as shown in the right side of Diagram 2.

(G) Ankle—measure the width of the end of the leg (P to Q), if intended to extend to the ankle, as in the right side of Diagram 2.

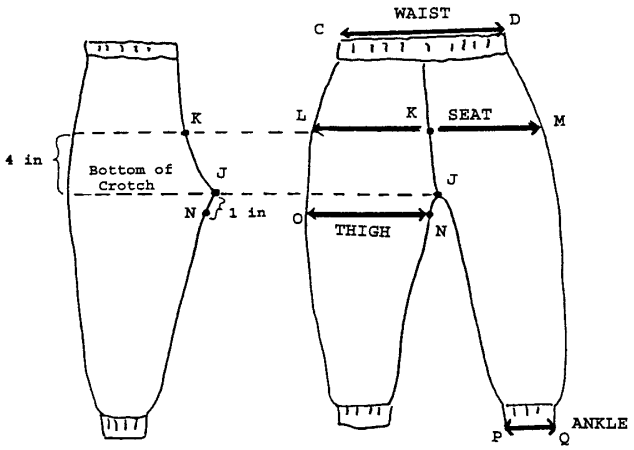


Diagram 2

* * * * *

PART 1616—STANDARD FOR THE FLAMMABILITY OF CHILDREN'S SLEEPWEAR: SIZES 7 THROUGH 14

1. The authority for part 1616 continues to read as follows:

Authority: Sec. 4, 67 Stat. 112, as amended, 81 Stat 569–570; 15 U.S.C. 1193.

2. Section 1616.2 is amended by revising paragraph (m) introductory text and (m)(1) to read as follows:

§ 1616.2 Definitions.

* * * * *

(m) *Tight-fitting garment* means a garment which:

(1)(i) In each of the sizes listed below does not exceed the maximum dimension specified below for the chest, waist, seat, upper arm, thigh, wrist, or ankle:

	Chest	Waist	Seat	Upper arm	Thigh	Wrist	Ankle
Size 7 Boys [1]							
Maximum Dimension:							
Centimeters	63.5	58.4	66	18.7	37.2	13.0	18.7
(inches)	(25)	(23)	(26)	(7⅜)	(14⅝)	(5⅛)	(7⅜)
Size 7 Girls							
Maximum Dimension:							
Centimeters	63.5	58.4	67.3	18.7	38.7	13.0	18.7
(inches)	(25)	(23)	(26½)	(7⅜)	(15¼)	(5⅛)	(7⅜)
Size 8 Boys [1]							
Maximum Dimension:							
Centimeters	66	59.7	67.3	19.4	38.4	13.3	19.1
(inches)	(26)	(23½)	(26½)	(7⅝)	(15⅛)	(5¼)	(7½)

	Chest	Waist	Seat	Upper arm	Thigh	Wrist	Ankle
Size 8 Girls							
Maximum Dimension:							
Centimeters	66	59.7	71.1	19.4	41.3	13.3	19.1
(inches)	(26)	(23½)	(28)	(7⅝)	(16¼)	(5¼)	(7½)
Size 9 Boys [1]							
Maximum Dimension:							
Centimeters	68.6	61.0	69.2	20	39.7	13.7	19.4
(inches)	(27)	(24)	(27¼)	(7⅞)	(15⅝)	(5⅜)	(7⅝)
Size 9 Girls							
Maximum Dimension:							
Centimeters	68.6	61.0	73.7	20	42.6	13.7	19.4
(inches)	(27)	(24)	(29)	(7⅞)	(16¾)	(5⅜)	(7⅝)
Size 10 Boys [1]							
Maximum Dimension:							
Centimeters	71.1	62.2	71.1	20.6	41.0	14	19.7
(inches)	(28)	(24½)	(28)	(8⅛)	(16⅛)	(5½)	(7¾)
Size 10 Girls							
Maximum Dimension:							
Centimeters	71.1	62.2	76.2	20.6	43.8	14	19.7
(inches)	(28)	(24½)	(30)	(8⅛)	(17¼)	(5½)	(7¾)
Size 11 Boys [1]							
Maximum Dimension:							
Centimeters	73.7	63.5	73.7	21	42.2	14.3	20
(inches)	(29)	(25)	(29)	(8¼)	(16⅝)	(5⅝)	(7⅞)
Size 11 Girls							
Maximum Dimension:							
Centimeters.							
Centimeters	73.7	63.5	78.7	21	45.1	14.3	20
(inches)	(29)	(25)	(31)	(8¼)	(17¾)	(5⅝)	(7⅞)
Size 12 Boys [1]							
Maximum Dimension:							
Centimeters	76.2	64.8	76.2	21.6	43.5	14.6	20.3
(inches)	(30)	(25½)	(30)	(8½)	(17⅛)	(5¾)	(8)
Size 12 Girls							
Maximum Dimension:							
Centimeters	76.2	64.8	81.3	21.6	46.7	14.6	20.3
(inches)	(30)	(25½)	(32)	(8½)	(18½)	(5¾)	(8)
Size 13 Boys [1]							
Maximum Dimension:							
Centimeters	78.7	66	78.7	22.2	44.8	14.9	20.6
(inches)	(31)	(26)	(31)	(8¾)	(17⅝)	(5⅞)	(8⅛)
Size 13 Girls							
Maximum Dimension:							
Centimeters	78.7	66	83.8	22.2	47.6	14.9	20.6
(inches)	(31)	(26)	(33)	(8¾)	(18¾)	(5⅞)	(8⅛)
Size 14 Boys [1]							
Maximum Dimension:							
Centimeters	81.3	67.3	81.3	22.9	46	15.2	21
(inches)	(32)	(26½)	(32)	(9)	(18⅛)	(6)	(8¼)

	Chest	Waist	Seat	Upper arm	Thigh	Wrist	Ankle
Size 14 Girls							
Maximum Dimension:							
Centimeters	81.3	67.3	86.4	22.9	49.5	15.2	21
(inches)	(32)	(26½)	(34)	(9)	(19½)	(6)	(8¼)

[1] Garments not explicitly labeled and promoted for wear by girls must not exceed these maximum dimensions.

(ii) **Note:** Measure the dimensions on the front of the garment. Lay garment, right side out, on a flat, horizontal surface. Smooth out wrinkles. Measure distances as specified below and multiply them by two. Measurements should be equal to or less than the maximum dimensions given in the standards.

(A) Chest—measure distance from arm pit to arm pit (A to B) as in Diagram 1.

(B) Waist—See Diagram 1. *One-piece garment,* measure at the narrowest location between arm pits and crotch (C to D). *Two-piece garment,* measure width at both the bottom/sweep of the upper piece (C to D) and, as in Diagram 3, the top of the lower piece (C to D).

(C) Wrist—measure the width of the end of the sleeve (E to F), if intended to extend to the wrist, as in Diagram 1.

(D) Upper arm—draw a straight line from waist/sweep D through arm pit B to G. Measure down the sleeve fold from G to H. Refer to table below for G to H distances for each size. Measure the upper arm of the garment (perpendicular to the fold) from H to I as shown in Diagram 1.

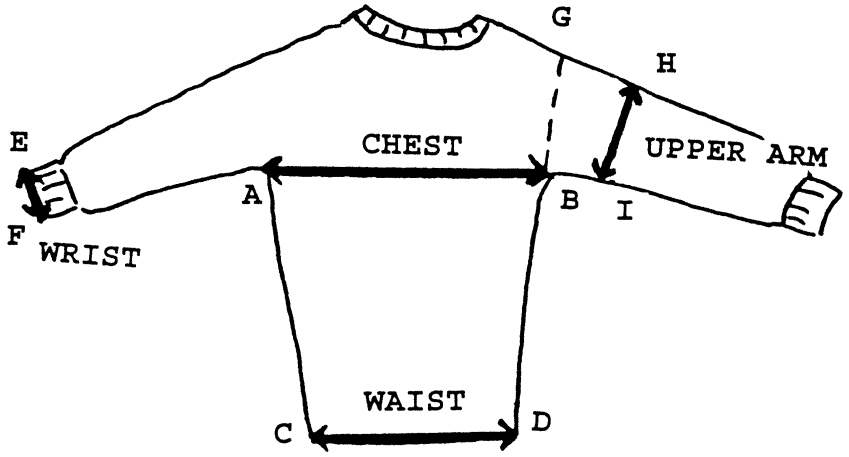


Diagram 1

DISTANCE FROM SHOULDER (G) TO (H) FOR UPPER ARM MEASUREMENT FOR SIZES 7 THROUGH 14

7	8	9	10	11	12	13	14
11.4 cm 4½″	11.7 cm 4″	11.9 cm 4¾″	12.5 cm 4″	12.8 cm 5″	13.1 cm 5″	13.7 cm 5″	14.2 cm 5″

(E) Seat—Fold the front of the pants in half to find the bottom of the crotch at J as in the left side of Diagram 2. The crotch seam and inseam intersect at J. Mark point K on the crotch seam at 4 inches above and perpendicular to the bottom of the crotch. Unfold the garment as in the right side of Diagram 2. Measure the seat from L to M through K as shown.

(F) Thigh—measure from the bottom of the crotch (J) 1 inch down the inseam to N as in the left side of Diagram 2. Unfold the garment and measure the thigh from the inseam at N to O as shown in the right side of Diagram 2.

(G) Ankle—measure the width of the end of the leg (P to Q), if intended to extend to the ankle, as in the right side of Diagram 2.

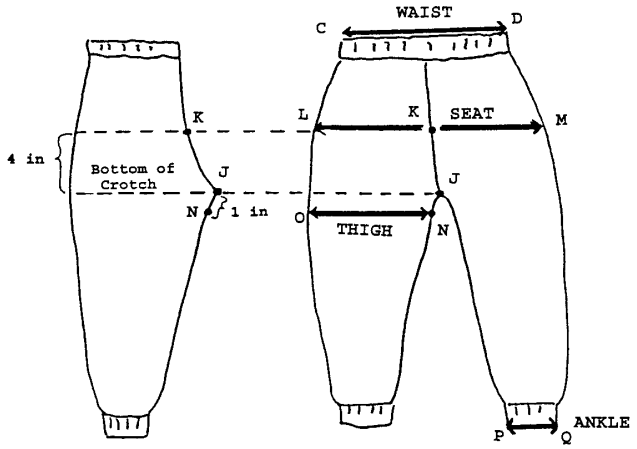


Diagram 2

* * * * *

Dated: May 12, 1998.

Sadye E. Dunn,

Secretary, Consumer Product Safety Commission.

References

The following documents contain information relevant to this rulemaking proceeding and are available for inspection at the Office of the Secretary, Consumer Product Safety Commission, Room 502, 4330 East-West Highway, Bethesda, Maryland:

1. Memorandum from Margaret Neily, Project Manager, Directorate for Engineering, to the Commission, ''Children's Sleepwear Flammability Standards—Technical Amendments,'' April 27, 1998.
2. Report from C. Craig Morris, Ph.D., Directorate for Epidemiology and Health Sciences, ''Clothing-Related Thermal Burns in Children Under 15 Years Old.'' March 1998.
3. Memorandum from Margaret Neily, Project Manager, Directorate for Engineering, to File, ''Technical Amendments of the Children's Sleepwear Flammability Standards—Snug-fitting'' Requirements, March 31, 1998.
4. Memorandum from Terrance R. Karels, Directorate for Economic Analysis, to Margaret Neily, Project Manager, ''Children's Sleepwear Update,'' April 9, 1998.
5. Memorandum from Terrance R. Karels, Directorate for Economic Analysis, to Margaret Neily, Project Manager, ''Economic Considerations of Revisions to the Children's Sleepwear Standard,'' April 9, 1998.
6. Memorandum from Patricia Fairall, Program Manager to Margaret Neilly, Project Manager, ''Industry Request for clarification of sleepwear segregation of tight-fitting garments,'' March 3, 1998.
7. Carolyn Meiers, Directorate for Engineering, to Margaret Neily, Project Manager, ''Methodology for Structured Sleepwear Observations,'' March 31, 1998.
8. ASTM Standards D4910–95a and D5826–95.
9. Anthropometry of Infants, Children, and Youths to Age 18 for Product Safety Design. Highway Safety Research Institute. Ann Arbor, Michigan: University of Michigan (1977).
10. Log of February 18, 1998 meeting, prepared by Margaret Neily, ''Children's Sleepwear—snug-fitting requirements,'' March 4, 1998.
11. Memorandum from Linda Fansler, Division of Engineering, Lab Sciences, to Margaret Neily, Project Manager, ''Tolerance,'' April 8, 1998.

[FR Doc. 98–13026 Filed 5–20–98; 8:45 am]

BILLING CODE 6355–01–P

CONSUMER PRODUCT SAFETY COMMISSION

16 CFR Parts 1615 and 1616

Proposed Clarification of Statement of Policy; Standard for the Flammability of Children's Sleepwear: Sizes 0 Through 6X; Standard for the Flammability of Children's Sleepwear: Sizes 7 Through 14

AGENCY: Consumer Product Safety Commission.

ACTION: Proposed clarification of statement of policy.

SUMMARY: The Commission proposes to amend the policy statements on the flammability of children's sleepwear so that infant garments (sized for a child nine months and under) and ''tight-fitting'' garments (as defined in the sleepwear standards) can be marketed and promoted with other sleepwear.[1]

DATES: Written comments concerning this proposed amendment are due not later than August 4, 1998.

ADDRESSES: Comments should be mailed to the Office of the Secretary, Consumer Product Safety Commission, Washington, D.C. 20207; telephone:

[1] The Commission voted 2–0 to propose clarifying the enforcement policy statement. Commissioners Mary Gall and Thomas Moore voted in favor of issuing the proposal. Chairman Ann Brown abstained.

(301) 504–0800 or delivered to the Office of the Secretary, Room 501, 4330 East-West Highway, Bethesda, Maryland 20814. Copies should be submitted in five copies and captioned ''Sleepwear Policy Statement.'' Comments may also be filed by telefacsimile to (301) 504–0127 or by e-mail to cpsc os@cpsc.gov.

FOR FURTHER INFORMATION CONTACT: Patricia Fairall, Program Manager, Office of Compliance, Consumer Product Safety Commission, Washington, D.C. 20207; telephone (301) 504–0400, extension 1369.

SUPPLEMENTARY INFORMATION:

A. Background

The Consumer Product Safety Commission enforces two flammability standards for children's sleepwear. The flammability standard for children's sleepwear in sizes 0 through 6X is codified at 16 CFR Part 1615. The flammability standard for children's sleepwear in sizes 7 through 14 is codified at 16 CFR Part 1616.

On September 9, 1996, the Commission issued a final rule amending the flammability standards for children's sleepwear to exclude from the definition of ''children's sleepwear,'' codified at 16 CFR 1615.1(a) and 1616.2(a), (1) garments sized for infants nine months of age or younger and (2) tight-fitting garments for children older than nine months. 61 FR 47634. The Commission found that such tight-fitting garments did not present an unreasonable risk of injury. Rather, the Commission's information showed that many severe incidents occurred with loose-fitting garments such as oversized t-shirts used inappropriately as sleepwear. The Commission concluded that garments fitting closely and that touch the body at key points should be exempt from the sleepwear standards because they do not present the same risk as loose-fitting garments. These amendments became effective on January 1, 1997. However, the Commission also issued a stay of enforcement for close-fitting garments which are labeled and promoted as underwear. That stay expires on June 9, 1998.

B. Clarification

The Commission has become aware that the garment industry is concerned about the policy statements in 16 CFR 1615.64(d) and 1616.65(d), which suggest segregation of items covered by the children's sleepwear standards from all fabrics and garments that are beyond the scope of the children's sleepwear standards. The purpose of the September 9, 1996 final rule was to allow garments sized for a child nine months and under and tight-fitting garments in sizes above nine months to be sold and used as sleepwear. Therefore, the Commission proposes to modify the policy statements at 1615.64(d) and 1616.65(d) to provide that infant garments (defined in the amended sleepwear standard at 16 CFR 1615.1(c)(1) as sized for a child nine months and under) and ''tight-fitting'' garments (defined in the amended sleepwear standard at 16 CFR 1615.1(o) and 1616.2(m)) can be marketed and promoted with other sleepwear.

For the reasons stated above and pursuant to the authority of Section 4 of the Flammable Fabrics Act (15 U.S.C. 1193), the Commission proposes to amend 16 CFR 1615.64 and 1616.65 to read as follows:

PART 1615—STANDARD FOR THE FLAMMABILITY OF CHILDREN'S SLEEPWEAR: SIZES 0 THROUGH 6X

1. The authority citation for part 1615 continues to read as follows:

Authority: Sec. 4, 67 Stat. 112, as amended, 81 Stat. 569–70; 15 U.S.C. 1193.

2. Section 1615.64 is amended by revising paragraph (d) introductory text to read as follows:

§ 1615.64 Policy to clarify scope of the standard.

* * * * *

(d) Retailers, distributors, and wholesalers, as well as manufacturers, importers, and other persons (such as converters) introducing a fabric or garment into commerce which does not meet the requirements of the flammability standards for children's sleepwear, have an obligation not to promote or sell such fabric or garment for use as an item of children's sleepwear. Also, retailers, distributors, and wholesalers are advised not to advertise, promote, or sell as an item of children's sleepwear any item which a manufacturer, importer, or other person (such as a converter) introducing the item into commerce has indicated by label, invoice, or, otherwise, does not meet the requirements of the children's sleepwear flammability standards and is not intended or suitable for use as sleepwear. ''Infant garments'' as defined by § 1615.1(c) and ''tight-fitting'' garments as defined by § 1615.1(o) are exempt from the standard which requires flame resistance. They may be marketed as sleepwear for purposes of this section. Additionally, retailers are advised:

* * * * *

PART 1616—STANDARD FOR THE FLAMMABILITY OF CHILDREN'S SLEEPWEAR: SIZES 7 THROUGH 14

1. The authority citation for part 1616 continues to read as follows:

Authority: Sec. 4, 67 Stat. 112, as amended, 81 Stat. 569–70; 15 U.S.C. 1193.

2. Section 1616.65 is amended by revising paragraph (d) introductory text to read as follows:

§ 1616.65 Policy scope of the standard.

* * * * *

(d) Retailers, distributors, and wholesalers, as well as manufacturers, importers, and other persons (such as converters) introducing a fabric or garment into commerce which does not meet the requirements of the flammability standards for children's sleepwear, have an obligation not to promote or sell such fabric or garment for use as an item of children's sleepwear. Also, retailers, distributors, and wholesalers are advised not to advertise, promote, or sell as an item of children's sleepwear any item which a manufacturer, importer, or other person (such as a converter) introducing the item into commerce has indicated by label, invoice, or, otherwise, does not meet the requirements of the children's sleepwear flammability standards and is not intended or suitable for use as sleepwear. ''Tight-fitting'' garments as defined by § 1616.2(m) are exempt from the standard which requires flame resistance. They may be marketed as sleepwear for purposes of this section. Additionally, retailers are advised:

* * * * *

Dated: May 12, 1998.

Sadye E. Dunn,

Secretary, Consumer Product Safety Commission.

[FR Doc. 98–13028 Filed 5–20–98; 8:45 am]

BILLING CODE 6355–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

21 CFR Part 334

[Docket No. 78N–036L]

RIN 0910–AA01

Laxative Drug Products for Over-the-Counter Human Use; Proposed Amendment to the Tentative Final Monograph

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Food and Drug Administration (FDA) is amending the tentative final monograph for over-the-counter (OTC) laxative drug products to include additional general and professional labeling for oral and rectal dibasic sodium phosphate/monobasic sodium phosphate (sodium phosphates) drug products. FDA is proposing new warnings and directions for these products and a new time to effect statement for rectal products based on new data submitted after publication of the tentative final monograph for OTC laxative drug products. This proposal is part of the ongoing review of OTC drug products conducted by FDA. Elsewhere in this issue of the **Federal Register** the agency is finalizing the package size limitation and warning prior to the completion of the final monograph for OTC laxative drug products.

DATES: Submit written comments or objections by August 19, 1998.

ADDRESSES: Submit written comments to the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857.

FOR FURTHER INFORMATION CONTACT: Cheryl A. Turner, Center for Drug Evaluation and Research (HFD–560), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20857, 301–827–2222.

SUPPLEMENTARY INFORMATION:

I. Background

In the **Federal Register** of March 21, 1975 (40 FR 12902), FDA published, under 21 CFR 330.10(a)(6), an advance notice of proposed rulemaking to establish a monograph for OTC laxative, antidiarrheal, emetic, and antiemetic drug products, together with the recommendations of the Advisory Review Panel on OTC Laxative, Antidiarrheal, Emetic, and Antiemetic Drug Products (the Panel), which was the advisory review panel responsible for evaluating data on the active ingredients in these classes. The Panel recommended monograph status for phosphate salts, such as sodium biphosphate [1] and sodium phosphate [2] (40 FR 12902 at 12940).

The agency's proposed regulation, in the form of a tentative final monograph, for OTC laxative drug products was published in the **Federal Register** of January 15, 1985 (50 FR 2124). The agency also proposed monograph status for sodium phosphates oral solution [3]. (See proposed § 334.58(d)(5)(i), 50 FR 2124 at 2152 and 2155.) In addition to its use as an OTC laxative for the relief of occasional constipation, sodium phosphates oral solution is used as part of a bowel cleansing regimen in preparing a patient for surgery or for preparing the colon for x-ray or endoscopic examination. (See proposed § 334.80(a)(2), 50 FR 2124 at 2157.) Sodium phosphates oral solution and sodium phosphates enema [4], respectively, are the current United States Pharmacopeia (USP) names for the oral and rectal dosage forms of the combination of sodium phosphates ingredients.

In the **Federal Register** of March 31, 1994 (59 FR 15139), the agency proposed to amend the tentative final monograph for OTC laxative drug products to limit the OTC container size for sodium phosphates oral solution to not greater than 90 milliliters (mL). The agency noted that the major trade product containing sodium phosphates oral solution was marketed in 45-mL, 90-mL, and 240-mL bottles. The purgative dose or dose used for colonoscopy is 45 mL. Because the product was available in three sizes, the manufacturer's labeling advised physicians to prescribe by volume and not to prescribe by the bottle and not to exceed the recommended dosage, as serious side effects may occur. Despite this labeling, the multiple container sizes available in the marketplace have caused consumer confusion and appear to have been involved in several consumer deaths (59 FR 15139 at 15140).

Because of the reported cases of accidental overdosing and the confusion that has occurred between 240-mL and 90-mL container sizes, the agency proposed that the 240-mL size container of sodium phosphates oral solution should no longer remain in the OTC marketplace. In the interest of safety, the agency proposed to limit the maximum OTC container size for this product to 90 mL.

The agency proposed to include the package size limitation and a warning (informing consumers not to exceed the recommended dosage unless directed by a doctor) in the monograph for OTC laxative drug products. However, that monograph has not been finalized to date. Because of the potential serious safety risk involved, elsewhere in this issue of the **Federal Register** the agency is finalizing the package size limitation and warning prior to the completion of the final monograph for OTC laxative drug products. The agency is including this information in part 201 (21 CFR part 201) at this time and will incorporate it into the final monograph for OTC laxative drug products at a later date.

Based on new data submitted since the January 15, 1985, and the March 31, 1994, proposals were published, the agency is proposing in this document additional general and professional labeling for oral and rectal sodium phosphates products for OTC laxative use. In the **Federal Register** of February 27, 1997 (62 FR 9024), FDA proposed to establish a standardized format for the labeling of OTC drug products. When the agency finalizes that proposal, the agency will also amend the final version of the rule proposed herein, as needed, to conform to the final labeling rule. Copies of previous rulemakings discussed above and information that has come to the agency's attention since publication of the proposals are on public display in the Dockets Management Branch (address above).

II. The Agency's Labeling Proposals for Sodium Phosphates

A. Introduction

One comment informed the agency of modifications made in the labeling of its rectal enema sodium phosphates product. The comment had expanded the professional labeling to include additional warning statements regarding use in patients with a colostomy, congenital megacolon, imperforate anus, impaired renal function, heart disease, congestive heart failure, preexisting electrolyte disturbances (such as dehydration or those secondary to the use of diuretics), or in patients using calcium channel blockers, diuretics, or other medications that may affect electrolyte levels, as hypocalcemia, hyperphosphatemia, hypernatremia, and acidosis may occur. The comment cited several references (Refs. 1, 2, and 3) to support its warning statements. The professional labeling also included information on the treatment of electrolyte imbalances. The comment stated that the labeling no longer recommends the use of this enema product in children under 2 years of age. The comment mentioned that a summarized version of the professional

[1] The Panel designated this ingredient ''sodium biphosphate.'' However, monobasic sodium phosphate is currently the official name for this ingredient in the *USP Dictionary of USAN and International Drug Names*, 1997.

[2] The Panel designated this ingredient ''sodium phosphate.'' However, dibasic sodium phosphate is currently the official name for this ingredient in the *USP Dictionary of USAN and International Drug Names*, 1997.

[3] Sodium phosphates oral solution is the official name for a solution of dibasic sodium phosphate and monobasic sodium phosphate in the *U.S. Pharmacopeia 23/National Formulary 18*, 1995.

[4] Sodium phosphates enema is the official name for a solution of dibasic sodium phosphate and monobasic sodium phosphate in the *U.S. Pharmacopeia 23/National Formulary* 18, 1995.

labeling will appear on the product's retail carton.

The agency agrees with the comment that the professional labeling for these sodium phosphates products should be expanded to include more information for health professionals to ensure safe use. As a result of the comment's additional warnings, the agency has reevaluated all of the labeling for sodium phosphates products (oral and rectal). The agency notes that the comment included calcium channel blockers in its professional warning. However, the agency is not aware of any specific data to show that sodium phosphates products should not be used in patients taking calcium channel blockers. Therefore, calcium channel blockers will not be included in the professional warning for sodium phosphates products at this time.

B. Professional Labeling

In § 334.80(b)(2) of the tentative final monograph for OTC laxative drug products (50 FR 2124 at 2157), the agency proposed the following warnings in the professional labeling for products containing sodium phosphates: ''Do not use in patients with megacolon, as hypernatremic dehydration may occur. Use with caution in patients with impaired renal function.'' The comment's labeling and information in the literature provide a basis to expand this warning. Individuals with impaired renal function (Refs. 4 through 8, including the elderly (Ref. 5)), heart disease (Refs. 8, 9, and 10), acute myocardial infarction (Refs. 11 and 12), unstable angina (Ref. 12), dehydration (Refs. 1 and 9), or who are on diuretics (Ref. 10) are at risk for an electrolyte imbalance to occur with use of oral and rectal sodium phosphates products. Sodium phosphates can cause alterations in serum levels of sodium, potassium, phosphate, chloride, and calcium and, in some people, such changes can be life threatening. The reduction of calcium levels reflects changes in ionized calcium (Ref. 13). Hypocalcemia with subsequent low levels of ionized calcium may result in neuromuscular irritability, heart block, and cardiovascular failure (Ref. 13). Therefore, the agency has determined that the warnings in the professional labeling for oral and rectal sodium phosphates products in proposed § 334.80(b)(2) (redesignated as § 334.80(b)(2)(i) in this proposal) should be expanded. The agency has made an effort to present the warning information in a new format using specific headings to make it clearer and more readable as follows:

''Do not use'' (these three words in bold print) ''in patients with congestive heart failure.''

''Use with caution'' (these three words in bold print) ''in patients with impaired renal function, heart disease, acute myocardial infarction, unstable angina, preexisting electrolyte disturbances (such as dehydration or those secondary to the use of diuretics), the elderly, or people taking drugs that may affect electrolyte levels.''

The agency is also including the following information regarding prevention and treatment of an electrolyte imbalance.

''Monitor electrolytes.'' (these two words in bold print) ''Give sufficient fluid replacement with all oral and rectal sodium phosphates products to prevent dehydration.'' ''What can occur:'' (these three words in bold print) ''Hypocalcemia, hyperphosphatemia, hypernatremia, hypokalemia, and acidosis. These conditions are more likely to occur when more than one dose of sodium phosphates is given in a 24-hour period.''

''What you should do:'' (these four words in bold print) ''Advise people to follow recommended dose. Treatment of electrolyte imbalance may require immediate medical intervention with appropriate electrolyte and fluid replacement. (Some examples of references for treatment of this condition are Fonkalsrud, E., and J. Keen, Hypernatremic Dehydration Hypertonic Enemas in Congenital Megacolon, *The Journal of the American Medical Association*, 199:584586, 1967, and Edmondson, S., and T. D. Almquist, Iatrogenic Hypocalcemic Tetany, *Annals of Emergency Medicine*, 19:938–940, 1990.)''

The agency is including additional warnings for rectal sodium phosphates products because of reports of its misuse in certain individuals by health professionals. Fatal or life-threatening consequences have resulted from excess dosages of sodium phosphates enemas in adults (Refs. 4, 6, and 14) and in young children (Refs. 10, 15, and 16). The agency notes that many of these adverse effects occurred when sodium phosphates enemas were used in children under 2 years of age. Sodium phosphates enemas have also been misused in individuals with colon abnormalities (Refs. 1, 4, 10, 17, and 18) and rectal abnormalities (Refs. 5, 19, and 20). Individuals with a functional abnormality of the colon, e.g., a colostomy (Refs. 10, 21, and 22), imperforate anus (Refs. 4 and 21), atonic colon (Ref. 4), or congenital megacolon (Refs. 1, 4, 10, and 21) are at risk for hyperosmotic dehydration and hyperphosphatemia with the use of sodium phosphates enemas. Such individuals have a tendency to retain the enema for a prolonged period of time, and considerable absorption of the phosphate ion occurs. Several cases of rectal gangrene have occurred after an enema nozzle injury in individuals with hemorrhoids (Refs. 19, 20, and 23). The authors believed that the rectal injury was compounded due to the necrotizing effect of the sodium phosphates on the rectal tissue. Other reports (Refs. 19, 20, and 23 through 26) indicate that following an enema tip injury to the rectum, the presence of sodium phosphates causes a pronounced inflammatory response and tissue damage which, if untreated, can produce serious consequences. Based on the above, the agency is proposing to add the following warnings in the professional labeling in proposed § 334.80(b)(2)(ii) for sodium phosphates enemas to inform health professionals to carefully monitor use in certain individuals or not to use at all. This information is also presented in the new format using specific headings:

''Do not use'' (these three words in bold print) ''sodium phosphates enema in children under 2 years of age or in patients with congenital megacolon or imperforate anus because of the risk of hyperosmotic dehydration and hyperphosphatemia.''

''Stop using'' (these two words in bold print) ''if there is resistance to the enema tip. Forcing the tip into the rectum can result in a serious injury that requires immediate medical attention.''

''Use sodium phosphates enema with extreme caution'' (these seven words in bold print) ''in patients with a colostomy or atonic colon (because of the risk of hyperosmotic dehydration and hyperphosphatemia) or with a rectal abnormality, such as hemorrhoids (because sodium phosphates can cause serious damage to the rectal mucosa if an enema tip injury occurs). Using more than one sodium phosphates enema in a 24-hour period can cause serious electrolyte problems.''

The ''Do not use'' warning for sodium phosphates enemas in § 334.80(b)(2)(ii)(A) may be combined with the ''Do not use'' warning for all sodium phosphates products in § 334.80(b)(2)(i)(A). The warning proposed for sodium phosphates products in § 334.80(b)(2) of the tentative final monograph, which stated ''Do not use in patients with megacolon, as hypernatremic dehydration may occur. Use with caution in patients with impaired renal function,'' is superseded by the warnings in this amendment.

The agency notes that the comment stated that a summarized version of the professional labeling will appear on the product's retail package. Professional labeling is labeling provided to health professionals but not to the general public. Therefore, a summarized version of this professional labeling should not appear on the retail package. As discussed in section II.C of this document, the agency has developed labeling for sodium phosphates products that it believes adequately

informs consumers of the proper use of these products.

C. OTC Labeling

In § 334.58(c)(2)(i) of the tentative final monograph (50 FR 2124 at 2155), the agency proposed the following warning for products containing sodium phosphates: ''Do not use this product if you have kidney disease, unless directed by a doctor.'' The agency is proposing to expand the warning for oral and rectal products that contain sodium phosphates because consumers who have kidney disease (Refs. 4 through 7), heart problems (Refs. 8 through 12), or are dehydrated (Refs. 1 and 9) should not use sodium phosphates products, unless directed by a doctor.

The agency has also determined that a new warning is needed to restrict the number of days that all oral and rectal sodium phosphates products can be used, unless directed by a doctor. The Panel in its report (40 FR 12902 at 12941) and the agency in the tentative final monograph (50 FR 2124 at 2153) recommended that the use of sodium phosphates be restricted to 1 week (7 days). However, the agency has reviewed new data indicating that sodium phosphates can cause electrolyte imbalances within 24 hours after the initial dose is taken (Refs. 4, 11, and 12) (also see the final rule for oral and rectal OTC sodium phosphates drug products published elsewhere in this issue of the **Federal Register**). These blood level changes have occurred in individuals with no underlying renal failure or active heart disease (Refs. 11, 12, and 27). The agency is concerned that daily use of sodium phosphates products for 7 days may cause significant changes in the sodium, potassium, phosphate, chloride, and/or calcium blood levels. In the interest of consumer safety and to help reduce the risk of adverse effects that can occur from sequential doses of sodium phosphates, the agency believes that use of sodium phosphates should be limited to 3 days instead of 7 days. The revised warning for oral and rectal sodium phosphates, which appears in proposed § 334.58(c)(2)(i), states: ''Do not use if'' (these four words in bold print) ''you have kidney disease, heart problems, or are dehydrated, or for more than 3 days, without asking a doctor.''

In § 334.58(c)(2)(ii) of the tentative final monograph (50 FR 2124 at 2155), the agency proposed the following warning for oral dosage forms of sodium phosphates identified in § 334.16(d), (e), or (f): ''Do not give to children under 5 years of age unless directed by a doctor.'' However, the agency is proposing to revise the directions for oral sodium phosphates products in new § 201.307(b)(3)(ii) (21 CFR 201.307(b)(3)(ii)) (designated as § 334.58(d)(5)(i) in this proposal) and in proposed § 334.58(d)(6) and (d)(7) to be consistent with other oral OTC laxative drug products. (See section II.D of this document.) Therefore, for consistency, the proposed warning in § 334.58(c)(2)(ii) for oral sodium phosphates is revised to state: ''Do not give to children under 6 years of age, without asking a doctor.''

In § 334.58(c)(2)(iii) of the tentative final monograph (50 FR 2124 at 2155), the agency proposed the following warning for sodium phosphates enemas: ''Do not give to children under 2 years of age unless directed by a doctor.'' The agency also proposed the following direction for sodium phosphates enemas in § 334.58(d)(5)(ii) (50 FR 2124 at 2155): ''* * * Children under 2 years of age: consult a doctor.'' However, because of adverse effects that have occurred when sodium phosphates enemas were used in children under 2 years of age, the agency is revising the warning and direction statements. Therefore, in § 334.58(c)(2)(iii) of this proposal, the revised warning for sodium phosphates rectal products states: ''Do not use in children under 2 years of age.'' The corresponding direction, which appears in § 334.58(d)(5)(ii)(A) in this proposal, is revised to state: ''* * * Do not use in children under 2 years of age.'' The agency believes it is necessary to have this information in both the warning and direction sections of the labeling because of the adverse effects that can occur when sodium phosphates enemas are used in children under 2 years of age.

D. Directions

Effectiveness is not increased when a sodium phosphates enema is retained more than 5 minutes (Refs. 28, 29, and 30). Data indicate that a sodium phosphates enema is usually expelled from the rectum within 20 minutes (Refs. 28, 29, and 30) and that increased blood levels of phosphorus and sodium and decreased levels of calcium can occur within several hours (Refs. 13, 17, and 30) if the enema is retained. Therefore, the agency is proposing a new direction for sodium phosphates rectal products in § 334.58(d)(5)(ii)(B) in this proposal, which states: ''If no urge is felt after 5 minutes of using, try to empty bowel. Call a doctor promptly if no liquid comes out of the rectum after 30 minutes because dehydration could occur.''

The agency is proposing a new direction in § 334.58(d)(5)(ii)(C) for sodium phosphates rectal products. A sodium phosphates enema can cause serious damage to the rectal mucosa if the enema tip causes a rectal injury (Refs. 19, 20, and 23). If the enema tip perforates the rectum, antibiotic treatment or a temporary colostomy may be needed to prevent sepsis (Refs. 23 through 26, and 31). All rectal bleeding resulting from an enema tip injury should be medically evaluated because rectal perforations can be painless (Refs. 20, 25, and 31). Therefore, the new direction states: ''Stop using if tip is hard to insert. Forcing the tip into the rectum can cause injury (especially if you have hemorrhoids). If enema tip causes rectal bleeding or pain, get immediate medical care.''

The agency is aware that labeling that was submitted to the Panel (Ref. 32) and currently marketed labeling (Ref. 33) for oral sodium phosphates products contain dosages for children 5 to 9 years of age, and for children 10 and 11 years of age. The Panel in its report (40 FR 12902 at 12940) and the agency in the tentative final monograph (50 FR 2124 at 2155) recommended dosages of oral sodium phosphates products for these age groups. Elsewhere, in this issue of the **Federal Register**, the agency included the above age ranges in the directions in new § 201.307(b)(3)(ii). The agency notes that the directions for sodium phosphates oral solution contain separate dosages for children 10 and 11 years of age, and for children 5 to 9 years of age. These age ranges are not consistent with age ranges used for the majority of OTC laxative drug products, which recommend dosages for children 6 to 11 years of age.

Therefore, the agency is proposing to revise the directions for oral sodium phosphates products in new § 201.307(b)(3)(ii) (designated as § 334.58(d)(5)(i) in this proposal), and in proposed § 334.58(d)(6) and (d)(7) to be consistent with other oral OTC laxative drug products. The proposed directions in § 334.58(d)(5)(i) state:

> * * * Children 6 to 9 years of age: Oral dosage is dibasic sodium phosphate 0.86 to 1.89 g and monobasic sodium phosphate 2.2 to 5.05 g (5 to 10 mL dibasic sodium phosphate/monobasic sodium phosphate oral solution) as a single daily dose. 'Do not take more than 10 mL (2 teaspoonfuls) in a 24-hour period.' Children under 6 years of age: ask a doctor.

The proposed directions in § 334.58(d)(6) for products containing dibasic sodium phosphate identified in § 334.16(e) state: ''* * * Children 6 to 9 years of age: Oral dosage is 0.86 to 1.89 g in a single daily dose. Children under 6 years of age: ask a doctor.'' The

proposed directions in § 334.58(d)(7) for products containing monobasic sodium phosphate identified in § 334.16(f) state: ''* * * Children 6 to 9 years of age: Oral dosage is 1.12 to 5.05 g in a single daily dose. Children under 6 years of age: ask a doctor.''

E. Time to Effect

The agency is proposing to revise the time to effect statement in proposed § 334.58(b)(2) for sodium phosphates rectal products from 2 to 15 minutes to 1 to 5 minutes. In three studies (Refs. 28, 29, and 30), 98 subjects (280 observations) were evaluated to determine the time to effect following use of sodium phosphates enema. In 98 percent of the observations (33 subjects accounted for 261/280 observations), the reported time to effect was within 10 minutes. In 83 percent of the observations, the time to effect was between 1 and 5 minutes. The average time to effect was 4 to 5 minutes and the mode was 3 to 5 minutes. The data do not indicate that sodium phosphates is more effective if the solution is retained more than 5 minutes (Refs. 28, 29, and 30). Therefore, the agency is proposing to revise § 334.58(b)(2) to state: ''This product generally produces bowel movement in 1 to 5 minutes.''

The agency invites specific comments on these proposed labeling statements. The agency will discuss its decision on these labeling proposals in a future issue of the **Federal Register**. Until the agency makes a final determination on these labeling statements, the agency encourages all manufacturers of sodium phosphates products voluntarily to label their products to include the proposed labeling statements. Because FDA is encouraging that the proposed labeling statements be used on a voluntary basis at this time, the agency will give manufacturers ample time after publication of a final rule to use up any labeling implemented in conformance with this document.

III. References

The following references have been placed on display in the Dockets Management Branch (address above) and may be seen by interested persons between 9 a.m. and 4 p.m., Monday through Friday.

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IV. Summary of the Agency's Proposal for OTC Laxative Drug Products Containing Sodium Phosphates

Based on new information, the agency is proposing changes in the labeling for oral and rectal sodium phosphates drug products. A summary of the changes proposed in this document follows.

1. The agency is revising proposed § 334.16(d), (e), and (f) of the monograph to use the current USP names for dibasic sodium phosphate/monobasic sodium phosphate (sodium phosphates) drug products. (See section I of this document.)

2. The agency is revising the warning proposed in § 334.58(c)(2)(ii) for

products containing oral sodium phosphates identified in § 334.16(d), (e), and (f) to state: ''Do not give to children under 6 years of age, without asking a doctor.''(See section II.C of this document.)

3. The agency is revising the directions for oral sodium phosphates in new § 201.307(b)(3)(ii) (designated as § 334.58(d)(5)(i) in this proposal) and in proposed § 334.58(d)(6) and (d)(7) to be consistent with other oral OTC laxative drug products. The directions will include oral dosages for children 6 years of age and older and state to ask a doctor for children under 6 years of age. (See section II.D of this document.)

4. The agency is changing the ''time to effect'' statement proposed in § 334.58(b)(2) for rectal dosage forms of sodium phosphates from 2 to 15 minutes to 1 to 5 minutes. (See section II.E of this document.)

5. The agency is expanding the warning for oral and rectal sodium phosphates proposed in § 334.58(c)(2)(i) to state: ''Do not use if'' (these four words in bold print) ''you have kidney disease, heart problems, or are dehydrated, or for more than 3 days, without asking a doctor.'' (See section II.C of this document.)

6. The agency is revising the warning proposed for rectal dosage forms of sodium phosphates in § 334.58(c)(2)(iii) which stated, ''Do not give to children under 2 years of age unless directed by a doctor,'' to read: ''Do not use in children under 2 years of age.'' The agency is also revising the direction proposed for rectal sodium phosphates in § 334.58(d)(5)(ii) which stated, ''Children under 2 years of age: consult a doctor,'' with a new direction in § 334.58(d)(5)(ii)(A) that states: ''Do not use in children under 2 years of age.'' (See section II.C of this document.)

7. The agency is proposing new directions for rectal dosage forms of sodium phosphates in § 334.58(d)(5)(ii)(B) that state: ''If no urge is felt after 5 minutes of using, try to empty bowel. Call a doctor promptly if no liquid comes out of the rectum after 30 minutes because dehydration could occur.'' (See section II.D of this document.)

8. The agency is proposing new directions in § 334.58(d)(5)(ii)(C) for rectal dosage forms of sodium phosphates that state: ''Stop using if tip is hard to insert. Forcing the tip into the rectum can cause injury (especially if you have hemorrhoids). If enema tip causes rectal bleeding or pain, get immediate medical care.'' (See section II.D of this document.)

9. The agency is revising the professional labeling for oral and rectal sodium phosphates proposed in § 334.80(b)(2) to include additional ''Do not use'' and ''Use with caution'' warnings. The agency is also including new information about monitoring electrolytes and treating electrolyte imbalances. The new warnings and other information appear in § 334.80(b)(2)(i) and (b)(2)(ii). (See section II.B of this document.)

10. The agency has made an effort to shorten and simplify some of the labeling, e.g., by using the phrase ''without asking a doctor'' instead of ''unless directed by a doctor.'' The agency has also proposed a new format for professional labeling. The agency believes that these changes will provide a clear and readable format for these labeling statements. FDA is inviting specific comments on this labeling format and on the wording of these statements.

V. Analysis of Impacts

FDA has examined the impacts of the proposed rule under Executive Order 12866 and the Regulatory Flexibility Act (5 U.S.C. 601–612). Executive Order 12866 directs agencies to assess all costs and benefits of available regulatory alternatives and, when regulation is necessary, to select regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity). Under the Regulatory Flexibility Act, if a rule has a significant economic impact on a substantial number of small entities, an agency must analyze regulatory options that would minimize any significant impact of the rule on small entities.

Title II of the Unfunded Mandates Reform Act (2 U.S.C. 1501 *et seq.*) requires that agencies prepare a written statement and economic analysis before proposing any rule that may result in an expenditure in any 1 year by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation).

The agency believes that this proposed rule is consistent with the principles set out in the Executive Order and in these two statutes. The purpose of this proposed rule is to add warning and direction statements to the general OTC and health professional (for health professionals only) labeling of oral and rectal OTC sodium phosphates drug products. These warning and direction statements concern product toxicity and are intended to help ensure the safe and effective use of all OTC sodium phosphates drug products. Potential benefits include reduced toxicity when consumers use, and health professionals recommend, these products.

The agency has been informed that relabeling costs of the type required by this proposed rule (changes to both consumer and professional labeling) generally average about $3,000 to $4,000 per stock keeping unit (SKU) (individual products, packages, and sizes). The agency is aware of 3 manufacturers that together produce 4 SKU's of oral sodium phosphates drug products and approximately 125 SKU's of rectal sodium phosphates drug products. There may be a few additional small manufacturers or a few additional products in the marketplace that are not identified in the sources FDA reviewed. Assuming that there are about 130 affected OTC SKU's in the marketplace, total one-time costs of relabeling would be $390,000 to $520,000.

The agency also believes that actual costs could be lower for several reasons. First, most of the label changes will be made by private label manufacturers that tend to use simpler and less expensive labeling. Second, labeling changes would not be required until the final monograph for OTC laxative drug products is issued and becomes effective. The agency is proposing a 12-month implementation period that would allow the manufacturers to coordinate these changes with routinely scheduled label printing and/or other revisions required by the final monograph for OTC laxative drug products. Thus, relabeling costs for these products would be mitigated or reduced by the cost of other labeling changes that the final monograph will also require.

The proposed rule would not require any new reporting and recordkeeping activities. Therefore, no additional professional skills are needed. There are no other Federal rules that duplicate, overlap, or conflict with the proposed rule.

The agency considered but rejected several labeling alternatives: (1) Voluntary relabeling, (2) publication of the labeling information in the *FDA Drug Bulletin* or professional journals, and (3) an exemption from coverage for small entities. The agency does not consider the first or third alternative acceptable because they do not assure that consumers or health professionals will have the most recent needed information for safe and effective use of these sodium phosphates drug products. The agency considers the second alternative useful and may proceed with such publications. However, such publications do not provide a permanent labeling requirement, which

the agency considers necessary for these products.

This proposed rule may have a significant economic impact on the manufacturers of these products, all of which are considered to be small entities, using the U.S. Small Business Administration designations for this industry (750 employees). The agency believes that any other unidentified manufacturer of these products is also likely to be a small entity. These manufacturers will need to change the information panel of each affected sodium phosphates SKU and print new professional labeling. Among the steps the agency is taking to minimize the impact on these small entities are: (1) To provide 1 year for implementation to enable entities to use up existing labeling stock, and (2) to allow these labeling changes to be coordinated with other labeling changes required by the final monograph. The agency believes that these actions should help reduce the relabeling cost for small entities.

The agency considered but rejected both a shorter and a longer implementation period. While the agency would like to have this new labeling in place as soon as possible, it considers a period less than 1 year difficult for manufacturers to implement all of the labeling required by the final monograph. The agency considered a longer effective date but finds it unacceptable because it would not assure that consumers have the most recent needed information for safe and effective use of OTC sodium phosphates drug products at the earliest possible time. Manufacturers are encouraged to implement the new labeling as soon as possible after the final monograph is published.

The analysis shows that this proposed rule is not economically significant under Executive Order 12866 and that the agency has undertaken important steps to reduce the burden to small entities. Nevertheless, some entities, especially those private label manufacturers that provide labeling for a number of the affected products, may incur significant impacts. Thus, this economic analysis, together with other relevant sections of this document, serves as the agency's initial regulatory flexibility analysis, as required under the Regulatory Flexibility Act. Finally, this analysis shows that the Unfunded Mandates Act does not apply to the proposed rule because it would not result in an expenditure in any 1 year by State, local, and tribal governments, in the aggregate, or by the private sector, of $100 million.

The agency invites public comment regarding any substantial or significant economic impact that this rulemaking would have on OTC laxative drug products containing sodium phosphates. Comments regarding the impact of this rulemaking on OTC laxative drug products containing sodium phosphates should be accompanied by appropriate documentation. The agency is providing a period of 90 days from the date of publication of this proposed rulemaking in the **Federal Register** for development and submission of comments on this subject. The agency will evaluate any comments and supporting data that are received and will reassess the economic impact of this rulemaking in the preamble to the final rule.

VI. Paperwork Reduction Act of 1995

FDA tentatively concludes that the labeling requirements proposed in this document are not subject to review by the Office of Management and Budget because they do not constitute a ''collection of information'' under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq*.). Rather, the proposed labeling statements are a ''public disclosure of information originally supplied by the Federal government to the recipient for the purpose of disclosure to the public'' (5 CFR 1320.3(c)(2)).

VII. Environmental Impact

The agency has determined under 21 CFR 25.31(c) that this action is of a type that does not individually or cumulatively have a significant effect on the human environment. Therefore, neither an environmental assessment nor an environmental impact statement is required.

VIII. Request for Comments

Interested persons may, on or before August 19, 1998, submit written comments or objections on the proposed regulation to the Dockets Management Branch (address above). Three copies of all comments or objections are to be submitted, except that individuals may submit one copy. Comments should be identified with the docket number found in brackets in the heading of this document and may be accompanied by a supporting memorandum or brief. Received comments and objections may be seen in the office above between 9 a.m. and 4 p.m., Monday through Friday.

FDA is proposing that any final rule based on this proposal be effective 12 months after the date of its publication in the **Federal Register**.

List of Subjects in 21 CFR Part 334

Labeling, Over-the-counter drugs.

Therefore, under the Federal Food, Drug, and Cosmetic Act and under authority delegated to the Commissioner of Food and Drugs, it is proposed that 21 CFR part 334 (proposed in the **Federal Register** of January 15, 1985, 50 FR 2124) be amended as follows:

PART 334—LAXATIVE DRUG PRODUCTS FOR OVER-THE-COUNTER HUMAN USE

1. The authority citation for 21 CFR part 334 continues to read as follows:

Authority: 21 U.S.C. 321, 351, 352, 353, 355, 360, 371.

2. Section 334.16 is amended by revising paragraphs (d), (e), and (f) to read as follows:

§ 334.16 Saline laxative active ingredients.

* * * * *

(d) Dibasic sodium phosphate/ monobasic sodium phosphatemarketed as a solution.

(e) Dibasic sodium phosphate.

(f) Monobasic sodium phosphate.

3. Section 334.58 is amended by revising paragraph (b)(2), by revising paragraph (c)(2), by revising the heading of paragraph (d)(5) and text of paragraph (d)(5)(i), by redesignating paragraph (d)(5)(ii) as (d)(5)(ii)(A) and revising new (d)(5)(ii)(A), by adding new paragraphs (d)(5)(ii)(B) and (d)(5)(ii)(C), and by revising the headings and text of paragraphs (d)(6) and (d)(7) to read as follows:

§ 334.58 Labeling of saline laxative drug products.

* * * * *

(b) * * *

(2) *Rectal dosage forms*. ''This product generally produces bowel movement in 1 to 5 minutes.''

(c) * * *

(2) *For products containing dibasic sodium phosphate or monobasic sodium phosphate identified in § 334.16(d), (e), or (f)*—(i) ''Do not use if'' (these four words in bold print) ''you have kidney disease, heart problems, or are dehydrated, or for more than 3 days, without asking a doctor.''

(ii) *Oral dosage forms*. ''Do not give to children 5 years of age and under, without asking a doctor.''

(iii) *Rectal dosage forms*. ''Do not use in children under 2 years of age.''

(d) * * *

(5) *For products containing dibasic sodium phosphate/ monobasic sodium phosphate identified in § 334.16(d) and marketed as a solution*—(i) Oral dosage. Adults and children 12 years of age and over: Oral dosage is dibasic sodium phosphate 3.42 to 7.56 grams and monobasic sodium phosphate 9.1 to 20.2 grams (20 to 45 milliliters (mL)

dibasic sodium phosphate/monobasic sodium phosphate oral solution) as a single daily dose. ''Do not take more than 45 mL (9 teaspoonfuls or 3 tablespoonfuls) in a 24-hour period.'' Children 10 and 11 years of age: Oral dosage is dibasic sodium phosphate 1.71 to 3.78 grams and monobasic sodium phosphate 4.5 to 10.1 grams (10 to 20 mL dibasic sodium phosphate/monobasic sodium phosphate oral solution) as a single daily dose. ''Do not take more than 20 mL (4 teaspoonfuls) in a 24-hour period.'' Children 6 to 9 years of age: Oral dosage is dibasic sodium phosphate 0.86 to 1.89 gram and monobasic sodium phosphate 2.2 to 5.05 grams (5 to 10 mL dibasic sodium phosphate/monobasic sodium phosphate oral solution) as a single daily dose. ''Do not take more than 10 mL (2 teaspoonfuls) in a 24-hour period.'' Children under 6 years of age: ask a doctor.

(ii) *Rectal enema dosage.* (A) Adults and children 12 years of age and over: Enema dosage is dibasic sodium phosphate 6.84 to 7.56 grams and monobasic sodium phosphate 18.24 to 20.16 grams in a single daily dose. Children 2 to 11 years of age: Enema dosage is dibasic sodium phosphate 3.42 to 3.78 grams and monobasic sodium phosphate 9.12 to 10.08 grams in a single daily dose. ''Do not use in children under 2 years of age.'' (Manufacturers should convert these dosages to the amount of solution to be used.)

(B) ''If no urge is felt after 5 minutes of using, try to empty bowel. Call a doctor promptly if no liquid comes out of the rectum after 30 minutes because dehydration could occur.''

(C) ''Stop using if tip is hard to insert. Forcing the tip into the rectum can cause injury (especially if you have hemorrhoids). If enema tip causes rectal bleeding or pain, get immediate medical care.''

(6) *For products containing dibasic sodium phosphate identified in § 334.16(e).* Adults and children 12 years of age and over: Oral dosage is 3.42 to 7.56 grams in a single daily dose. Children 10 to 11 years of age: Oral dosage is 1.71 to 3.78 grams in a single daily dose. Children 6 to 9 years of age: Oral dosage is 0.86 to 1.89 gram in a single daily dose. Children under 6 years of age: ask a doctor.

(7) *For products containing monobasic sodium phosphate identified in § 334.16(f).* Adults and children 12 years of age and over: Oral dosage is 4.5 to 20.2 grams in a single daily dose. Children 10 to 11 years of ages: Oral dosage is 2.25 to 10.1 grams in a single daily dose. Children 6 to 9 years of age: Oral dosage is 1.12 to 5.05 grams in a single daily dose. Children under 6 years of age: ask a doctor.

4. Section 334.80 is amended by redesignating paragraph (b)(2) as paragraph (b)(2)(i) and revising it, and by adding paragraph (b)(2)(ii), to read as follows.

§ 334.80 Professional labeling.

* * * * *

(b) * * *

(2) *For products containing dibasic sodium phosphate or monobasic sodium phosphate identified in § 334.16(d), (e), or (f)*—(i) *Oral and rectal dosage forms*—(A) ''Do not use'' (these three words in bold print) ''in patients with congestive heart failure.''

(B) ''Use with caution'' (these three words in bold print) ''in patients with impaired renal function, heart disease, acute myocardial infarction, unstable angina, preexisting electrolyte disturbances (such as dehydration or those secondary to the use of diuretics), the elderly, or people taking drugs that may affect electrolyte levels.''

(C) ''Monitor electrolytes.'' (these two words in bold print) ''Give sufficient fluid replacement with all oral and rectal sodium phosphates products to prevent dehydration.''

(D) ''What can occur:'' (these three words in bold print) ''Hypocalcemia, hyperphosphatemia, hypernatremia, hypokalemia, and acidosis. These conditions are more likely to occur when more than one dose of sodium phosphates is given in a 24-hour period.''

(E) ''What you should do:'' (these four words in bold print) ''Advise people to follow recommended dose. Treatment of electrolyte imbalance may require immediate medical intervention with appropriate electrolyte and fluid replacement. (Some examples of references for treatment of this condition are Fonkalsrud, E., and J. Keen, 'Hypernatremic Dehydration Hypertonic Enemas in Congenital Megacolon,' *The Journal of the American Medical Association*, 199:584–586, 1967, and Edmondson, S., and T. D. Almquist, 'Iatrogenic Hypocalcemic Tetany,' *Annals of Emergency Medicine*, 19:938–940, 1990.)''

(ii) *Rectal dosage forms.* (A) ''Do not use'' (these three words in bold print) ''sodium phosphates enema in children under 2 years of age or in patients with congenital megacolon or imperforate anus because of the risk of hyperosmotic dehydration and hyperphosphatemia.''

(B) ''Stop using'' (these two words in bold print) ''if there is resistance to the enema tip. Forcing the tip into the rectum can result in a serious injury that requires immediate medical attention.''

(C) ''Use sodium phosphates enema with extreme caution'' (these seven words in bold print) ''in patients with a colostomy or atonic colon (because of the risk of hyperosmotic dehydration and hyperphosphatemia) or with a rectal abnormality, such as hemorrhoids (because sodium phosphates can cause serious damage to the rectal mucosa if an enema tip injury occurs). Using more than one sodium phosphates enema in a 24-hour period can cause serious electrolyte problems.''

* * * * *

Dated: April 27, 1998.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 98–12054 Filed 5–20–98; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF TRANSPORTATION

Coast Guard

33 CFR Part 165

[CGDO1–98–002]

RIN 2121–AA97

Safety Zone; New York Super Boat Race, New York

AGENCY: Coast Guard, DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to establish a temporary safety zone in the lower Hudson River, for the New York Super Boat Race. The temporary safety zone would be in effect on Sunday, September 13, 1998, from 11:30 a.m. until 4:00 p.m. unless extended or terminated sooner by the Captain of the Port, New York. The proposed safety zone would restrict vessel traffic in the Lower Hudson River between Battery Park and Pier 76 in Manhattan. The proposed safety zone is needed to protect racing participants and spectator craft from the hazards associated with high speed powerboat racing.

DATES: Comments must be received on or before August 19, 1998.

ADDRESSES: Comments should be mailed to Lieutenant Junior Grade Alma Kenneally, Waterways Oversight Branch, Coast Guard Activities New York, 212 Coast Guard Drive, Staten Island, New York 10305.

FOR FURTHER INFORMATION CONTACT: Lieutenant Junior Grade Alma Kenneally, Waterways Oversight Branch, Coast Guard Activities New York (718) 354–4195.

SUPPLEMENTARY INFORMATION:

Request for Comments

The Coast Guard encourages interested persons to participate in this rulemaking by submitting written data, views, or arguments.

Persons submitting comments should include their names and addresses, identify this notice (CGD01–98–002) and the specific section of the proposal to which their comments apply, and give reasons for each comment. Persons wanting acknowledgment of receipt of comments should enclose a stamped, self-addressed postcard or envelope.

The Coast Guard will consider all comments received during the comment period. It may change this proposal in view of the comments. The Coast Guard plans no public hearing; however, persons may request a public hearing by writing to the Waterways Oversight Branch at the address under **ADDRESSES.** If it is determined that the opportunity for oral presentations will aid this rulemaking, the Coast Guard will hold a public hearing at a time and place announced by a later notice in the **Federal Register**.

Background and Purpose

Super Boat International Productions, Inc. has submitted an Application for Approval of Marine Event for a Super Boat Race in the waters of the Lower Hudson River. This regulation would establish a temporary safety zone in the waters of the Lower Hudson River south of a line drawn from the northwest corner of Pier 76 in Manhattan and a point in Weehawken, New Jersey at approximate position 40°45′52″N 074°01′01″W, and north of a line connecting the following points:

Latitude	*Longitude*
40°42′16.0″N	074°01′09.0″W, then south to
40°41′55.0″N	074°01′16.0″W, then southwest to
40°41′47.0″N	074°01′36.0″W, then northwest to
40°41′55.0″N	074°01′59.0″W, then to shore at
40°42′20.5″N	074°02′06.0″W.

The safety zone would be effective on Sunday, September 13, 1998, from 11:30 a.m. until 4:00 p.m., unless extended or terminated sooner by the Captain of the Port of New York. This safety zone would restrict vessel traffic in the Lower Hudson River south of a line drawn from Pier 76 in Manhattan to a point located directly opposite on the New Jersey shoreline and north of a line drawn between Battery Park in Manhattan and the southern most point of Ellis Island in the Upper New York Bay. This safety zone is needed to protect mariners from the hazards associated with a boat race in which the participants transit at excessive speeds.

This event will include up to 40 powerboats, 24 to 50 feet in length, racing on an 8 mile oval course at speeds in excess of 100 mph. No more than 100 spectator craft are expected for the event.

Regulatory Evaluation

This proposal is not a significant regulatory action under section 3(f) of Executive Order 12866 and does not require an assessment of potential costs and benefits under section 6(a)(3) of that order. It has been exempted from review by the Office of Management and Budget under that order. It is not significant under the regulatory policies and procedures of the Department of Transportation (DOT) (44 FR 11040; February 26, 1979). The Coast Guard expects the economic impact of this proposal to be so minimal that a full Regulatory Evaluation under paragraph 10(e) of the regulatory policies and procedures of DOT is unnecessary. This safety zone would restrict vessel traffic in the Lower Hudson River south of a line drawn from Pier 76 in Manhattan to a point located directly opposite on the New Jersey shoreline and north of a line drawn between Battery Park in Manhattan and the southern most point of Ellis Island in the Upper New York Bay on Sunday, September 13, 1998, from 11:30 a.m. until 4:00 p.m., unless extended or terminated sooner by the Captain of the Port of New York. Although this regulation would prevent traffic from transiting this area, the effect of this regulation would not be significant for several reasons: the volume of commercial vessel traffic transiting the Lower Hudson River on a Sunday is less than half of the normal daily traffic volume; pleasure craft desiring to view the event will be directed to designated spectator viewing areas outside the safety zone; pleasure craft can take an alternate route through the East River and the Harlem River; the duration of the event is limited to four and one half hours; the extensive advisories which will be made to the affected maritime community by Local Notice to Mariners, Safety Voice Broadcast, and facsimile notification.

Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601 et seq.), the Coast Guard must consider whether this proposal will have a significant economic impact on a substantial number of small entities. ''Small entities'' include independently owned and operated small businesses that are not dominant in their field and that otherwise qualify as ''small business concerns'' under Section 3 of the Small Business Act (21 U.S.C. 632).

For reasons set forth in the above Regulatory Evaluation, the Coast Guard expects the impact of this proposal to be minimal. The Coast Guard certifies under 5 U.S.C. 605(b) that this proposal will not have a significant economic impact on a substantial number of small entities. If, however, you think that your business or organization qualifies as a small entity and that this rule, is adopted, will have significant economic impact on your business or organization, please submit a comment explaining why you think it qualifies and in what way and to what degree this rule will economically affect it.

Collection of Information

This proposal contains no collection of information requirements under the Paperwork Reduction Act (44 U.S.C. 3501).

Federalism

The Coast Guard has analyzed this action in accordance with the principles and criteria contained in Executive Order 12612 and has determined that this proposal does not raise sufficient federal implications to warrant the preparation of a Federalism Assessment.

Environment

The Coast Guard has considered the environmental impact of this proposal and concluded that under Figure 2–1, paragraph 34(g), of Commandant Instruction M16475.1C, it is categorically excluded from further environmental documentation.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

Proposed Regulations

For reasons set out in the preamble, the Coast Guard proposes to amend 33 CFR Part 165 as follows:

PART 165—[AMENDED]

1. The authority citation for Part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 50 U.S.C. 191; 33 CFR 1.05–1(g), 6.04–1, 6.04–6, and 160.5; 49 CFR 1.46.

2. A temporary section 165.T01–002, is added to read as follows:

§ 165.T01–002 Safety Zone; New York Super Boat Race, Hudson River, New York and New Jersey.

(a) *Location.* The following area is a safety zone: All waters of the Lower Hudson River between Pier 76 in Manhattan and a point on the New Jersey shore in Weehawken, New Jersey at 40°45′52″N 074°01′01″W, and north of a line connecting the following points:

Latitude	*Logitude*
40°42′16.0″N	074°01′09.0″W, then south to
40°41′55.0″N	074°01′16.0″W, then west to
40°41′47.0″N	074°01′36.0″W, then northwest to
40°41′55.0″N	074°01′59.0″W, then to shore at
40°42′20.5″N	074°02′06.0″W.

(b) *Effective period.* This safety zone is in effect on Sunday, September 13, 1998, from 11:30 a.m. until 4 p.m., unless terminated sooner by the Captain of the Port New York.

(c) *Regulations.* (1) The general regulations contained in 33 CFR 165.23 apply.

(2) All persons and vessels shall comply with the instructions of the Coast Guard Captain of the Port or the designated on scene patrol personnel. U.S. Coast Guard patrol personnel include commissioned, warrant, and petty officers of the Coast Guard. Upon being hailed by a U.S. Coast Guard vessel via siren, radio, flashing light, or other means, the operator of a vessel shall proceed as directed.

Dated: May 8, 1998.

L.M. Brooks,

Captain, U.S. Coast Guard, Acting Captain of the Port, New York.

[FR Doc. 98–13581 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–15–M

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[OH115–1; FRL–6100–7]

Approval and Promulgation of Maintenance Plan Revisions; Ohio

AGENCY: Environmental Protection Agency, (USEPA).

ACTION: Proposed rule.

SUMMARY: The United States Environmental Protection Agency (USEPA) is proposing to approve an April 27, 1998, request from Ohio, for State Implementation Plan (SIP) maintenance plan revisions for the following maintenance areas in Ohio: Canton (Stark County), Cleveland (Lorain, Cuyahoga, Lake, Ashtabula, Geauga, Medina, Summit and Portage Counties), Columbus (Franklin, Delaware and Licking Counties), Steubenville (Jefferson County), Toledo (Lucas and Wood Counties), Youngstown (Mahoning and Trumbull Counties) as well as Clinton County, Columbiana County and Preble County. The revisions would remove the air quality triggers from each area's contingency plan. The contingency plans were included in these areas' maintenance plans to correct violations of the one hour ozone National Ambient Air Quality Standard (NAAQS).

DATES: Written comments on this proposal must be received on or before June 22, 1998.

ADDRESSES: Copies of the documents relevant to this action are available for inspection during normal business hours at the following location: Regulation Development Section, Air Programs Branch, (AR–18J), U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604.

Please contact Scott Hamilton at (312) 353–4775 before visiting the Region 5 office.

Written comments should be sent to: J. Elmer Bortzer, Chief, Regulation Development Section, Air Programs Branch, (AR–18J), U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604.

FOR FURTHER INFORMATION CONTACT: Scott Hamilton, Environmental Scientist, Regulation Development Section, Air Programs Branch (AR–18J), U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, (312) 353–4775.

SUPPLEMENTARY INFORMATION:

I. Attainment Areas in Ohio

Since the Clean Air Act (CAA) attainment status designations were made, all of the Ohio areas listed in the summary section of this **Federal Register** Notice have attained the one hour ozone standard and have been redesignated to attainment for ozone. As a requirement to being redesignated to attainment, these areas developed maintenance plans. The purpose of the maintenance plans is to assure maintenance of the one hour ozone NAAQS for at least ten years. Included in the maintenance plans were contingency provisions. The purpose of the contingency provisions are to identify and correct any violation of the one hour ozone NAAQS in a timely fashion. Triggers are included in the contingency provisions to identify the need to implement measures and correct air quality problems until such time as a revised maintenance or attainment plan could be developed to address the level of the air quality problem. Triggering events in the contingency plans could be linked to ozone air quality and/or an emission level of ozone precursors.

The maintenance plan approvals were finalized by USEPA and published in the **Federal Register** for these Ohio areas as follows: Canton and Youngstown (61 FR 3319; January 31, 1996), Cleveland (61 FR 20458; May 7, 1996), Columbus (61 FR 3591; February 1, 1996), Steubenville, Columbiana County and Preble County (60 FR 7453; February 8, 1995), Toledo (60 FR 39115; August 1, 1995) and Clinton County (61 FR 11560; March 21, 1996).

II. One Hour Ozone Standard Revocation

On July 18, 1998, USEPA finalized a revision to the NAAQS for ozone which changed the standard from 0.12 parts per million (ppm) averaged over one hour, to 0.08 ppm, averaged over eight hours. USEPA is revoking the one hour standard in separate rulemakings based on an area's attainment of the one hour ozone standard. The first round of revocations will be for areas attaining the one hour standard based on quality assured air monitoring data for the years 1994–1996. The second round of one hour ozone standard revocations will be for areas attaining the one hour standard based on quality assured air monitoring data for the years 1995–1997. After these two rulemakings are finalized, the USEPA intends to publish rulemakings on an annual basis revoking the one hour ozone standard for additional areas that come into attainment of the one hour standard.

On January 16, 1998, USEPA published a proposed rule (63 FR 2726) in the **Federal Register** proposing to revoke the one hour ozone standard in areas attaining the standard based on quality assured air monitoring data for the years 1994–1996 (first round of revocations). In that proposal, USEPA proposed to revoke the one hour ozone standard in the Ohio areas subject to this proposed action [Canton (Stark County), Cleveland (Lorain, Cuyahoga, Lake, Ashtabula, Geauga, Medina, Summit and Portage Counties), Columbus (Franklin, Delaware and Licking Counties), Steubenville (Jefferson County), Toledo (Lucas and Wood Counties), Youngstown (Mahoning and Trumbull Counties)] as

well as Clinton, Columbiana and Preble Counties.

On July 16, 1997, President Clinton issued a directive to Administrator Browner on implementation of the new ozone standard, as well as the current one hour ozone standard (62 FR 38421). In that directive the President laid out a plan on how the new ozone and particulate matter standards, as well as the current one hour standard, are to be implemented. A December 29, 1997, memorandum entitled ''Guidance for Implementing the 1-Hour and Pre-Existing PM10 NAAQS'' signed by Richard D. Wilson, USEPA's Acting Assistant Administrator for Air and Radiation reflected that directive. The purpose of this guidance document is to ensure that the momentum gained by States to attain the one hour ozone NAAQS was not lost when moving toward implementing the eight hour ozone NAAQS.

The guidance document explains that maintenance plans will remain in effect for areas where the one hour standard is revoked; however, those maintenance plans may be revised to withdraw certain contingency measure provisions that have not been triggered or implemented prior to USEPA's determination of attainment and revocation. Where the contingency measure is linked to the one hour ozone standard or air quality ozone concentrations, the measures may be removed from the maintenance plan. Measures linked to non-air quality elements, such as emissions increases or vehicle miles traveled, may be removed if the State demonstrates that removing the measure will not affect an area's ability to attain the eight hour ozone standard.

In other words, after the one hour standard is revoked for an area, USEPA believes it is permissible to withdraw contingency measures designed to correct violations of that standard. Therefore, since such measures were designed to address future violations of a standard that no longer exists, it is no longer necessary to retain them. Furthermore, USEPA believes that future attainment and maintenance planning efforts should be directed toward attaining the eight hour ozone NAAQS.

III. Review of the State Submittal

In a letter from Donald R. Schregardus, Director, Ohio Environmental Protection Agency (OEPA) received by USEPA on April 27, 1998, OEPA officially requested that all air quality triggers be deleted from the maintenance plans for the areas in Ohio now attaining the one hour ozone standard and where USEPA has proposed to revoke the one hour standard (the areas listed in the Summary Section). As part of the implementation of the eight hour ozone standard, the State's ozone air quality will be evaluated and eight hour attainment and nonattainment designations will be made. USEPA believes that Ohio's request is consistent with the December 29, 1997, guidance document and the July 16, 1997, Presidential Directive, and that the request is approvable.

The OEPA has officially announced a public hearing on this matter to be held on June 1, 1998.

This revision is being proposed under a procedure called parallel processing, whereby USEPA proposes rulemaking action concurrently with the State's procedures for amending its regulations. If the proposed revision is substantially changed USEPA will evaluate those changes and may publish another notice of proposed rulemaking. If no substantial changes are made other than any consistent with this notice, the USEPA will publish a final rulemaking on the revisions. The final rulemaking action by USEPA on Ohio's request to revise the maintenance plans to remove air quality triggers will occur only after the one hour ozone standard has been revoked in final and Ohio's public hearing documentation is submitted to the USEPA.

While Ohio requested that the air quality triggers in Dayton's maintenance plan be removed, USEPA has yet to propose revocation of the one hour standard for Dayton. Revocation of the one hour standard is a prerequisite for revising maintenance plans to remove contingency provisions. USEPA will address Dayton in a future rulemaking.

IV. USEPA Proposed Action

The USEPA is proposing to approve the requested revision to the above mentioned maintenance plans in Ohio. The USEPA is parallel processing this request concurrent with the state proceedings. Written comments must be received by USEPA on or by June 22, 1998.

V. Administrative Requirements

(A) Future Requests

Nothing in this action should be construed as permitting, allowing or establishing a precedent for any future request for revision to any SIP. Each request for revision to the SIP shall be considered separately in light of specific technical, economic, and environmental factors and in relation to relevant statutory and regulatory requirements.

(B) Executive Order 12866

The Office of Management and Budget has exempted this regulatory action from Executive Order 12866 review.

(C) Regulatory Flexibility

Under the Regulatory Flexibility Act, 5 U.S.C. section 600 *et seq.*, USEPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C. sections 603 and 604. Alternatively, USEPA may certify that the rule will not have a significant impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

SIP approvals under section 110 and subchapter I, part D of the 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 impose any new requirements, the Administrator certifies that it does not have a significant impact on any small entities affected. Moreover, due to the nature of the Federal-State relationship under the Act, preparation of a flexibility analysis would constitute Federal inquiry into the economic reasonableness of the State action. The Clean Air Act forbids USEPA to base its actions concerning SIPs on such grounds. *Union Electric Co.* v. *USEPA*, 427 U.S. 246, 256–66 (1976); 42 U.S.C. 7410(a)(2).

(D) Unfunded Mandates

Under Section 202 of the Unfunded Mandates Reform Act of 1995, signed into law on March 22, 1995, USEPA must undertake various actions in association with any proposed or final rule that includes a Federal mandate that may result in estimated costs to state, local, or tribal governments in the aggregate; or to the private sector, of $100 million or more. This Federal action approves pre-existing requirements under state or local law, and imposes no new requirements. Accordingly, no additional costs to state, local, or tribal governments, or the private sector, result from this action.

(E) Audit Privilege and Immunity Law

Nothing in this action should be construed as making any determination or expressing any position regarding Ohio's audit privilege and immunity law (Sections 3745.70–3745.73 of the Ohio Revised Code). USEPA will be reviewing the effect of the Ohio audit privilege and immunity law on various Ohio environmental programs,

including those under the Clean Air Act, and taking appropriate action(s), if any, after thorough analysis and opportunity for Ohio to state and explain its views and positions on the issues raised by the law. The action taken herein does not express or imply any viewpoint on the question of whether there are legal deficiencies in this or any Ohio Clean Air Act program resulting from the effect of the audit privilege and immunity law. As a consequence of the review process, the regulations subject to the action taken herein may be disapproved, federal approval for the Clean Air Act program under which they are implemented may be withdrawn, or other appropriate action may be taken, as necessary.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Hydrocarbons, Intergovernmental relations, Ozone, Nitrogen oxides, Implementation plans.

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

Dated: May 7, 1998.

Robert Springer,

Acting Regional Administrator, Region V.

[FR Doc. 98–13614 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[Region II Docket No. NY27–1–178, FRL–6101–5]

Approval and Promulgation of Implementation Plans; Emission Trade to Meet Reasonably Available Control Technology for the State of New York

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The EPA is proposing approval of a revision to the New York State Implementation Plan for ozone. This revision proposes to establish and require an emission trade between Niagara Mohawk Power Corporation and Champion International Paper Corporation which will result in both sources meeting the requirements of Reasonably Available Control Technology for oxides of nitrogen. The intended effect of this proposed action is to approve source-specific permit conditions, requiring the sources to trade emissions in accordance with requirements of the Clean Air Act, and resulting in emission reductions which will help toward attaining the national ambient air quality standards for ozone.

DATES: Comments must be received on or before June 22, 1998.

ADDRESSES: All comments should be addressed to: Ronald Borsellino, Chief, Air Programs Branch, U.S. EPA, Region II Office, 290 Broadway, 25th Floor, New York, New York 10007–1866. Copies of the state submittal and other information are available for public inspection during normal business hours, by appointment, at the Air Programs Branch, U.S. EPA, Region II Office, 290 Broadway, 25th Floor, New York, New York; as well as the New York State Department of Environmental Conservation, Division of Air Resources, 50 Wolf Road, Albany, New York 12233.

FOR FURTHER INFORMATION CONTACT: Richard Ruvo, Environmental Engineer, Air Programs Branch, U.S. EPA, Region II Office, 290 Broadway, 25th Floor, New York, New York 10007–1866; (212) 637–4014.

SUPPLEMENTARY INFORMATION:

I. Background

The Clean Air Act (the Act) requires that States develop Reasonably Available Control Technology (RACT) regulations for all major stationary sources of oxides of nitrogen (NO_X) in areas which have been classified as ''moderate,'' ''serious,'' ''severe,'' and ''extreme,'' ozone nonattainment areas, and in all areas of the Ozone Transport Region (OTR). The EPA has defined RACT as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility (44 FR 53762, Sept. 17, 1979). This requirement is established by sections 182(b)(2), 182(f), and 184(b) of the Act. The Act's NO_X requirements are further described in more detail in ''The General Preamble for Implementation of Title I of the Clean Air Act Amendments,'' (57 FR 13498, April 16, 1992) and ''The NO_X Supplement to the General Preamble'' (57 FR 55620, November 25, 1992).

The entire State of New York is included in the OTR, therefore RACT must be applied to all major stationary sources of NO_X emissions. New York State has defined a major stationary source for NO_X as a source in the New York City metropolitan area and the lower Orange County metropolitan area which has the potential to emit 25 tons per year (TPY) and as a source in the rest of the State which has the potential to emit 100 TPY.

New York State adopted its NO_X RACT regulation, part 227–2, on January 19, 1994. Part 227–2, section 2.5(b) allows for system-wide emissions averaging as a compliance strategy. The average must be weighted so the mass emission rate of the units in operation is equivalent to the mass emission rate that would be achieved if each operating unit individually met the applicable RACT emission limit. Averaging may include units owned and operated by the same person.

II. State Submittal

On November 8, 1995, New York proposed for comment special permit conditions for the Niagara Mohawk Power Corporation and the Champion International Paper Corporation for an emission trade to meet the NO_X RACT requirements of part 227–2. New York approved the special permit conditions on December 14, 1995, having received no public comments. On April 9, 1996, New York State submitted the special permit conditions to EPA as a source-specific revision to the State Implementation Plan (SIP) for ozone. New York submitted additional technical information on April 30, 1996, October 17, 1996 and December 5, 1996. The SIP revision was reviewed by EPA in accordance with the completeness criteria found at Title 40, part 51, appendix V of the *Code of Federal Regulations.* EPA determined the SIP revision to be administratively and technically complete in a June 4, 1996 letter to New York.

In the process of its review of the April 9, 1996 SIP revision, EPA noted deficiencies in the special permit conditions. In a February 6, 1997 letter, EPA requested New York to correct these deficiencies, delaying review of the SIP revision. New York re-proposed for comment the special permit conditions for the emission trade on September 24, 1997. New York approved the special permit conditions on December 2, 1997, having received no public comments. On February 2, 1998, New York submitted to EPA the December 2, 1997 special permit conditions. The February 2, 1998 submittal supplemented the original April 9, 1996 SIP revision.

For a more detailed discussion of New York's SIP submittal and EPA's proposed action, the reader is referred to the Technical Support Document (TSD) which was developed as part of this action. Copies of the TSD are found at the previously mentioned addresses.

III. Analysis of State Submittal

A. Facility Descriptions

Niagara Mohawk Power Corporation (NMPC) operates four fossil fuel-fired utility plants in New York State; the

Oswego, Albany, C.R. Huntley, and Dunkirk Steam Stations. There are two Titles of the Act which impose NO_X emission limits on NMPC's fossil fuel-fired generating plants. All of NMPC's fossil units became subject to the Title I NO_X RACT requirements as of May 31, 1995. NMPC's coal-fired units are also subject to the Title IV Acid Rain requirements for NO_X. However, the Title I NO_X RACT requirements established by New York in part 227–2 are currently more restrictive on NMPC's units than the emission limits established by the Title IV rules. NMPC has developed a plan to comply with the NO_X RACT emission limits through the installation of air pollution control technology. In addition to these controls, NMPC uses a system-wide averaging scheme as a fallback to meeting the NO_X RACT requirements.

Champion International Paper Corporation (Champion) owns and operates two coal-fired boilers at its paper mill in Deferiet, Jefferson County. Under part 227–2, the two boilers are subject to the NO_X RACT emission limit of 0.5 lbs/MMBtu (pounds per million British Thermal Units). Stack tests completed in October 1995 and May 1997 indicated average NO_X emissions ranging from 0.665 lbs/MMBtu to 0.893 lbs/MMBtu.

Champion determined it would be technically infeasible for the two boilers to meet the NO_X RACT emission limit with conventional NO_X control technologies. Champion initially planned to meet the NO_X RACT requirements through the compliance option of repowering. However, after discussions with NMPC and New York, Champion decided to achieve compliance with RACT, as prescribed by part 227–2, by utilizing beyond-RACT emission reductions from the NMPC system-wide averaging plan.

B. Special Permit Conditions for the Emission Trade

New York has modified the permits for both NMPC and Champion in order to allow the implementation of the emission trade. For NMPC, which is creating the emission reductions, the special permit conditions require emissions of NO_X to be reduced below RACT-allowable emissions by the amount to be traded. For Champion, which will be using NMPC's emission reductions, the special permit conditions allow emissions of NO_X to be emitted in excess of the RACT-allowable emissions, but only by 90% of the amount to be traded.

The special permit conditions for NMPC, allow compliance to be demonstrated on either a unit-by-unit basis or on a system-wide average. Surplus NO_X reductions, in pounds, are calculated as the difference between the amount of NO_X allowed to be emitted by a given unit (lbs/MMBtu) and the actual amount of NO_X emitted by the unit (lbs/MMBtu), multiplied by the actual heat input, in MMBtu. Surplus NO_X reductions are calculated each hour for each unit. Compliance on a daily basis is determined by summing the surplus NO_X reductions created by each unit for each 24-hour period. From September 16 of each year to April 30 of the following year, compliance is based on a 30-day rolling average (Btu-weighted). The special permit conditions include example spreadsheets and tables to be used in tracking the surplus NO_X reductions for each unit and for the entire system and demonstrating compliance. The TSD includes a step-by-step example of an emission averaging calculation.

The source of the data used to calculate NMPC's NO_X emissions (lbs/MMBtu and heat input) will be the Continuous Emissions Monitors that have been installed pursuant to 40 CFR part 75. All of NMPC's fossil fired units are subject to the monitoring requirements of 40 CFR part 75. NMPC will submit quarterly compliance reports to New York to meet the NO_X RACT reporting requirements, showing the amount of NO_X generated each hour for each unit, and a summary of exceedances, should they occur.

In order for NMPC to demonstrate RACT compliance and to apply additional surplus NO_X reductions toward RACT compliance at the Champion Deferiet facility, NMPC will calculate the net amount of surplus NO_X reductions that were created by the NMPC system. The special permit conditions also require NMPC to hold at least 1.4 tons (2,800 pounds) of surplus NO_X reductions at the end of each 30-day rolling period, from September 16 to April 30, inclusive. From May 1 to September 15, NMPC must hold at least 1.3 tons (2,600 pounds) of surplus NO_X reductions at the end of each 24-hour period. In the event that less than 1.3 tons are held from May 1 to September 15, NMPC must notify New York and within five days must hold surplus NO_X reductions equal to the shortfall, multiplied by 1.10. Failure to hold the appropriate amount of surplus NO_X reductions, based on the time of the year, is considered a violation of the permit.

Champion's special permit conditions determine compliance using two formulas, depending on the time of year. Both formulas ensure Champion's boilers will not exceed 0.50 lbs/MMBtu, by subtracting the surplus NO_X reductions received from NMPC, in pounds, from Champion's daily NO_X emissions, in pounds, then dividing that by the daily heat input in MMBtu. Compliance with the 30-day rolling average will be determined by adding the amount of NO_X, in pounds, emitted during the previous 29 days (minus the amount of surplus NO_X reductions available for compliance) to the NO_X emitted during the most recently completed day (minus the amount of surplus NO_X reductions available for compliance that day), and dividing that sum by the sum of the daily heat inputs for the most recently completed 30 days.

The actual NO_X emissions rate for Champion's boilers will be determined through annual emissions testing as the average of three runs at maximum load. Such testing will be conducted using EPA Test Method 7E, with State oversite. Emission results will be used to calculate NO_X mass emissions for the period following testing, not to be applied for the previous year. Champion must maintain records for a period of at least five years of the (1) quantity of coal burned each day, (2) stack test reports, (3) daily total steam flow for each boiler, (4) daily prorated NO_X rate for the combined boilers, and (5) records of surplus NO_X reductions, creditable surplus NO_X reductions and the 10% set-aside.

For Champion, the amount of surplus NO_X reductions available from NMPC for compliance is 1.3 tons or 1.4 tons per day, depending on the time of year, therefore the amount of surplus NO_X reductions needed for compliance will not exceed 1.3 or 1.4 tons per day. From May 1 to September 15, creditable surplus NO_X reductions will be generated daily and defined as the daily difference between the surplus NO_X reductions generated by NMPC and those needed by Champion. In the event NMPC is unable, on a daily basis, to generate surplus NO_X reductions sufficient to satisfy Champion's need, the difference will be deducted from the creditable surplus NO_X reductions accumulated during the previous 30-day period. In the event NMPC notifies Champion that surplus NO_X reductions will be unavailable for a period of 30 consecutive days or more, Champion must submit an alternative NO_X RACT Compliance Plan to New York within 60 days. The Compliance Plan shall include the use of any or all creditable surplus NO_X reductions to remain in compliance with part 227–2 until implementation of the alternative NO_X RACT Compliance Plan. The Compliance Plan will include a plan to comply with the provisions of part 227–

2, a schedule for implementing RACT, and the use of creditable surplus NO_X reductions to offset emissions during the interim period of submittal and implementation of the RACT plan.

The special permit conditions also require Champion to set aside 10% of the 497.2 TPY received from NMPC for use by Champion as a benefit to the environment. Therefore only 447.48 TPY will be used by Champion for compliance purposes, while 49.72 TPY will be retired to benefit the environment.

The special permit conditions will terminate if the Champion Deferiet facility permanently shuts down or if NMPC and Champion terminate their agreement. The special permit conditions will also terminate if New York approves an alternate means for Champion to comply with RACT, such as, some other emission trade subject to EPA approval, or direct compliance with part 227–2 through the implementation of NO_X control technologies and strategies.

C. Consistency of the Emission Trade With Part 227–2 and EPA's Emission Trading Guidance Documents

The special permit conditions for NMPC and Champion include formulas to provide that the emission trade is on a Btu-weighted basis. These formulas ensure that the generation and calculation of surplus NO_X reductions are based on the units in operation during the compliance period. The formulas also ensure the mass emission rate of the units in operation is equivalent to the mass emission rate that would be achieved if each operating unit individually met the applicable RACT emission limit. The NMPC and Champion compliance plans clearly indicate which units at which facility will be included with the emission trade. Since the emission trade includes units owned and operated by two different persons, New York submitted this emission average as a source-specific SIP revision. Lastly, the affected facilities are located in Upstate New York, outside of the New York City severe nonattainment area. Therefore, it is not necessary to include any geographical constraints in the special permit conditions with respect to trades outside severe nonattainment areas, pursuant to part 227–2, section 2.5(b).

The April 9, 1996 submittal letter provides the evidence that New York has the legal authority under State law to approve and implement the compliance plan. The special permit conditions were processed in accordance with part 621.14 for inclusion in the Certificate to Operate. New York proposed approval of the SIP revision pursuant to part 227–2. Any violation of the special conditions of each source's permit will be enforced as prescribed by Chapter 19 of the New York State Environmental Conservation Law. The emission trade is enforceable through appropriate averaging times, test methods, compliance schedules, and reporting and recordkeeping requirements and is acceptable to the Agency. To verify compliance, NMPC and Champion are required to calculate daily averaged NO_X emissions records and submit these records in quarterly reports as prescribed by the special permit conditions. These conditions ensure compliance on a daily basis and include data obtained exclusively during operating hours to establish the average daily NO_X emissions.

Overall, part 227–2 provides a compliance option for owners of multiple affected units to choose cost-effective control options to meet an overall equivalent emission limit, in order to comply with part 227–2. Should a source not comply with this provision it would constitute a violation of part 227–2 and would subject the source owner or operator to civil and applicable criminal penalties. EPA believes this is sufficient to ensure that sources comply and should EPA have to take enforcement action, it could use the same provision to obtain compliance.

Since the 1970's, EPA has developed several emission trading programs and guidance documents to allow industry and States more flexibility in meeting statutory requirements of the Act. Overall, New York's emission trade between NMPC and Champion to meet the NO_X RACT requirements is consistent with EPA's emission trading guidance.

EPA's ''Emissions Trading Policy Statement'' (51 FR 43814, December 4, 1986) provides the Agency's historical guidance on emission trading programs (bubbles, netting, offsets and banking) to allow more flexibility in meeting Act requirements. The 1986 Policy discusses how only emission reductions which are surplus, quantifiable, enforceable and permanent may be used in an emission trade.

NMPC's NO_X emission reductions are surplus because the formulas in the special permit conditions are based on the difference between the amount of NO_X allowed to be emitted by RACT and the actual amount of NO_X emitted. Therefore, only those NO_X emission reductions below the RACT-allowable limits are considered surplus and available for use by Champion.

NMPC's NO_X emissions (lbs/MMBtu and heat input) are quantifiable through the Continuous Emissions Monitors that have been installed pursuant to 40 CFR part 75.

The legally-enforceable vehicles for the emission trade are the special permit conditions for NMPC and Champion, approved by New York on December 2, 1997.

NMPC's emission reductions used by Champion are considered permanent because NMPC's special permit conditions require NMPC to hold at least 1.3 or 1.4 tons of surplus NO_X reductions depending on the time of year. NMPC's NO_X emission reductions are also considered permanent because they are based on the implementation of various control strategies.

''The NO_X Supplement to the General Preamble'' (57 FR 55620, November 25, 1992) specifies that in cases where States adopt an areawide averaging rule for a group of sources, the emission limits, emission quantification methods, and monitoring and recordkeeping requirements applicable to each owner/operator in the group must be clearly specified. In addition, the rule must specify appropriate penalties for violation of the various requirements. Also, SIP measures must be converted into legally-enforceable vehicles such as a regulation or permit. EPA's current thinking is to also allow trading for other NO_X source categories, either within one facility, among several facilities or among several emission units at a facility.

While New York's averaging provision and this source-specific SIP revision are not intended to be a generic areawide trading rule, the Region believes this emission trade between NMPC and Champion is a logical extension of the NO_X Supplement. New York's emission trade between NMPC and Champion is consistent with EPA's general guidance (NO_X Supplement) on trading to meet the NO_X RACT requirements. The legally-enforceable vehicles for the emission trade are the special permit conditions for NMPC and Champion, approved by the New York on December 2, 1997. The permits clearly specify the emission limits, emission quantification methods, testing, monitoring and recordkeeping requirements applicable to each owner/operator in the trade. Civil and criminal sanctions associated with a violation of the special permit conditions are found within Article 71 of the State regulation.

EPA's Economic Incentive Program (EIP) Rules (40 CFR part 51, subpart U) contain the rules and guidance for EIP's that a State may choose to adopt for any criteria pollutant, as explicitly allowed for in the Act. The EIP rules provide an opportunity to encourage the

development and early implementation of appropriate EIP's. Since the EIP rules and guidance are broadly applicable to any kind of EIP, the guidance generally covers the same type of emission trading programs that have historically been addressed by the Emissions Trading Policy Statement. Therefore, trades which fall under the Emissions Trading Policy Statement represent one particular model for how States could choose to design such a program that would be approvable under the EIP rules.

Since the NMPC and Champion emission trade is consistent with the provisions of the Emissions Trading Policy Statement, it is also consistent with the EIP guidance. In addition to meeting the criteria in the Emissions Trading Policy Statement, the NMPC/Champion emission trade provides for additional emission reductions which meet the ''benefit-sharing'' goal of the EIP rules and guidance.

D. Summary

Major sources of NO_X are numerous and varied. As a result, New York has tried to allow for some flexibility in part 227–2. Part 227–2 allows owners and operators of multiple units to average emissions over all the units operated, with some appropriate restrictions. The use of post combustion control is not precluded for any source category. The owner or operator of a facility may choose to use post combustion control as a cost-effective control strategy for a particular application, as a means of ''over control'' for an averaging scheme or for use in an emission offset plan.

The source-specific SIP revision provides an innovative way for an affected source to achieve emission reductions (at less cost) equal to or beyond the reductions required by NO_X RACT. As a result of the emission trade, NMPC is required to create emission reductions of at least 1.3 or 1.4 tons of NO_X per day. As mentioned in its Fourth Quarter 1995 Compliance report, NMPC holds surplus NO_X reductions for Champion of 42 tons per 30-day rolling period (1.4 tons/day x 30 days). The report shows NMPC's 30-day compliance margin ranges from 323 to 543 tons, which is well beyond the amount to hold for Champion. For Champion, the emission trade allows the facility to exceed its NO_X allowable emissions, but only by the amount traded. For example, in a worst case scenario, emission increases by Champion will be contemporaneously offset by equivalent emission decreases at NMPC. Also, without the emission trade, Champion would have requested a waiver from New York, which if granted would have resulted in emission increases greater than 1.3 or 1.4 tons per day. In addition, Champion is required to retire 10% of the surplus NO_X reductions it receives from NMPC as a benefit to the environment.

EPA has reviewed NMPC's and Champion's applications and New York's source-specific SIP revision for completeness and approvability. EPA agrees with New York's determination that the emission trade between NMPC and Champion provides an innovative way for an affected source to achieve emission reductions equal to or beyond the reductions required by NO_X RACT, at less cost to industry. While this emission trade does not constitute traditional RACT, it does provide a compliance option for owners of multiple affected units to choose cost-effective control options to meet an overall emission reduction equivalent to RACT. The permit conditions for the emission trade serve as approved SIP emission limits for these facilities. Finally, EPA believes these permit conditions address the criteria of surplus, quantifiable, enforceable and permanent and therefore, proposes approval.

It should be noted that New York, the other OTR States and EPA, are developing future NO_X trading rules which will have broader applicability than this source-specific SIP revision. New York's adoption of the OTR's NO_X Budget Program and finalization of EPA's ''Ozone Transport SIP Call'' may replace the emission trade discussed in this proposed action, as well as establish an overall, generic emission trading program.

Conclusion: EPA is proposing full approval of the source-specific permit conditions requiring NMPC and Champion to trade emissions to meet the requirements of NO_X *RACT. EPA is proposing approval of these special permit conditions, as submitted by the State of New York on April 9, 1996 and supplemented on February 2, 1998, as part of the SIP.*

Nothing in this action should be construed as permitting or allowing or establishing a precedent for any future request for revision to any state implementation plan. Each request for revision to the state implementation plan shall be considered separately in light of specific technical, economic, and environmental factors and in relation to relevant statutory and regulatory requirements.

IV. Administrative Requirements

A. Executive Order 12866

The Office of Management and Budget (OMB) has exempted this regulatory action from review under Executive Order 12866.

B. Regulatory Flexibility Act

Under the Regulatory Flexibility Act, 5 U.S.C. 600 *et seq.*, EPA must prepare a regulatory flexibility analysis assessing the impact of any proposed or final rule on small entities. 5 U.S.C. 603 and 604. Alternatively, EPA may certify that the rule will not have a significant impact on a substantial number of small entities. Small entities include small businesses, small not-for-profit enterprises, and government entities with jurisdiction over populations of less than 50,000.

SIP approvals under 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 impose any new requirements, I certify that it does not have a significant impact on any small entities affected. Moreover, due to the nature of the Federal-State relationship under the CAA, preparation of a 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).

C. 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 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 approval action proposed 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 approves 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.

The Regional Administrator's decision to approve or disapprove the SIP revision will be based on whether it meets the requirements of section 110(a)(2)(A)-(K) and part D of the Clean Air Act, as amended, and EPA regulations in 40 CFR part 51.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Ozone, Reporting and recordkeeping requirements.

Authority: 42 U.S.C. 7401–7671q.

Dated: May 13, 1998

Herbert Barrack,

Acting Regional Administrator for Policy and Management.

[FR Doc. 98–13610 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 194

[FRL–6100–9]

RIN 2060–AG85

Opportunity To Comment on Documents Used by the Department of Energy To Certify the Rocky Flats Environmental Technology Site To Ship Transuranic Waste to WIPP, as Required in: Criteria for the Certification and Re-certification of the Waste Isolation Pilot Plant's Compliance With the Disposal Regulations: Certification Decision

AGENCY: Environmental Protection Agency.

ACTION: Notice of availability; opening of public comment period.

SUMMARY: The Environmental Protection Agency (EPA) is announcing the availability of, and soliciting public comments for 30 days on, Department of Energy (DOE) documents used to certify the Rocky Flats Environmental Technology Site (RFETS) to ship transuranic radioactive waste to the Waste Isolation Pilot Plant (WIPP). The documents include: ''Rocky Flats Environmental Technology Site Transuranic (TRU) Waste Management Manual'' (dated January 7, 1998) and ''Rocky Flats Environmental Technology Site Waste Isolation Pilot Plant Quality Assurance Project Plan'' (dated May 14, 1997). These documents are available for review in the public dockets listed in **ADDRESSES.** The EPA will be using these documents to evaluate RFETS's quality assurance and waste characterization programs and processes. The EPA will perform an inspection at RFETS the week of June 22–26, 1998.

DATES: EPA is requesting public comment on these documents. Comments must be received by EPA's official Air Docket on or before June 22, 1998.

ADDRESSES: Comments should be submitted to: Docket No. A–93–02, Air Docket, Room M–1500 (LE–131), U.S. Environmental Protection Agency, 401 M Street, S.W., Washington, DC 20460.

The DOE documents, ''Rocky Flats Environmental Technology Site Transuranic (TRU) Waste Management Manual'' (dated January 7, 1998) and ''Rocky Flats Environmental Technology Site Waste Isolation Pilot Plant Quality Assurance Project Plan'' (dated May 14, 1997) are available for review in the official EPA Air Docket in Washington DC, Docket No. A–93–02, Category X–B, and at the following three EPA WIPP informational docket locations in New Mexico: in Carlsbad at the Municipal Library, Hours: Monday–Thursday, 10am–9pm, Friday–Saturday, 10am–6pm, and Sunday 1pm–5pm; in Albuquerque at the Government Publications Department, Zimmerman Library, University of New Mexico, Hours: Monday–Thursday, 8am–9pm, Friday, 8am–5pm, Saturday–Sunday, 1pm–5pm; and in Santa Fe at the Fogelson Library, College of Santa Fe, Hours: Monday–Thursday, 8am–12am, Friday, 8am–5pm, Saturday, 9am–5pm, and Sunday, 1pm–9pm.

As provided in EPA's regulations at 40 CFR Part 2, and in accordance with normal EPA docket procedures, if copies of any docket materials are requested, a reasonable fee may be charged for photocopying.

FOR FURTHER INFORMATION CONTACT: Chuck Byrum, Office of Radiation and Indoor Air, (505) 665–7555 or call EPA's 24-hour toll-free WIPP Information Line, 1–800–331–WIPP.

SUPPLEMENTARY INFORMATION:

Background

The U.S. Department of Energy (DOE) is developing the Waste Isolation Pilot Plant (WIPP) near Carlsbad in southeastern New Mexico as a potential deep geologic repository for disposal of transuranic (TRU) radioactive waste. As defined by the WIPP Land Withdrawal Act (LWA) of 1992, as amended (Pub. L. No. 102–579), TRU waste consists of materials containing elements having atomic numbers greater than 92 (with half-lives greater than twenty years), in concentrations greater than 100 nanocuries of alpha-emitting TRU isotopes per gram of waste. Most TRU waste consists of items contaminated during the production of nuclear weapons, e.g., rags, equipment, tools, and organic and inorganic sludges.

On May 13, 1998, the U.S. Environmental Protection Agency (EPA) announced its final compliance certification decision to the Secretary of Energy. This decision states that the WIPP will comply with EPA's radioactive waste disposal regulations at 40 CFR Part 191 and the WIPP Compliance Criteria at 40 CFR Part 194.

The final WIPP certification decision includes conditions that (1) prohibit shipment of TRU waste for disposal at WIPP from any site other than the Los Alamos National Laboratory (LANL) until EPA determines that the site has established and executed a quality assurance program, in accordance with §§ 194.22(a)(2)(i), 194.24(c)(3), and 194.24(c)(5) for waste characterization activities and assumptions; and (2) prohibit shipment of TRU waste for disposal at WIPP from any site other than LANL until EPA has approved, in accordance with the approval process set forth at § 194.8(b), the procedures developed to comply with the waste characterization requirements of § 194.24(c)(4). As part of the EPA's decision-making process, DOE is required to submit to EPA appropriate documentation used to certify each DOE waste generator site for shipment of transuranic radioactive waste to WIPP. In accordance with § 194.8, EPA will place such documentation in the official Air Docket in Washington, D.C., and informational dockets in the State of New Mexico for public review and comment.

The documents submitted to EPA include: ''Rocky Flats Environmental Technology Site Transuranic (TRU) Waste Management Manual'' (dated January 7, 1998) and ''Rocky Flats Environmental Technology Site Waste Isolation Pilot Plant Quality Assurance Project Plan'' (dated May 14, 1997). The ''Rocky Flats Environmental Technology Site Transuranic (TRU) Waste Management Manual'' sets forth the waste characterization procedures for TRU wastes at Rocky Flats. The ''Rocky Flats Environmental Technology Site Waste Isolation Pilot Plant Quality Assurance Project Plan'' sets forth the quality assurance program that DOE purports to comply with the

requirements of § 194.22. After EPA reviews these documents for adequacy, EPA will conduct an inspection of a DOE audit of the site to determine whether the requirements set out in these documents are being adequately implemented in accordance with Conditions 2 and 3 of EPA's WIPP certification decision (Criteria for the Certification and Recertification of the Waste Isolation Pilot Plant's Compliance With the 40 CFR Part 191 Disposal Regulations: Certification Decision). Section 194.8 of the WIPP Compliance Criteria (as amended by the final certification decision) provides the public at least 30 days to comment on the documents placed in EPA's docket relevant to the site approval process.

If EPA determines that the provisions in the documents are adequately implemented, EPA will notify DOE by letter and place the letter in the official Air Docket in Washington DC, and in the informational docket locations in New Mexico. A positive approval letter will allow DOE to begin shipping TRU waste from RFETS. EPA will not make a determination of compliance before the inspection or before the 30-day comment period has closed.

Information on EPA's radioactive waste disposal standards (40 CFR Part 191), the compliance criteria (40 CFR Part 194), and EPA's certification decision is filed in the official EPA Air Docket, Dockets No. R–89–01, A–92–56, and A–93–02, respectively, and is available for review in Washington DC, and at the three EPA WIPP informational docket locations in New Mexico. The dockets in New Mexico contain only major items from the official Air Docket in Washington, DC, plus those documents added to the official Air Docket since the October 1992 enactment of the WIPP LWA.

Dated: May 14, 1998.

Richard D. Wilson,

Acting Assistant Administrator for Air and Radiation.

[FR Doc. 98–13606 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 73

[MM Docket No. 98–64; RM–9272]

Radio Broadcasting Services; St. Anne, IL

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: The Commission requests comments on a petition filed by STARadio Corporation proposing the allotment of Channel 293A at St. Anne, Illinois, as the community's first local aural transmission service. Channel 293A can be allotted to St. Anne in compliance with the Commission's minimum distance separation requirements with a site restriction of 10.6 kilometers (6.6 miles) southeast to avoid short-spacings to the licensed sites of Station WYBA(FM), Channel 292A, Lansing, Illinois, and Station WGCY(FM), Channel 292A, Gibson City, Illinois. The coordinates for Channel 293A at St. Anne are North Latitude 40–56–20 and West Longitude 87–39–10.

DATES: Comments must be filed on or before July 6, 1998, and reply comments on or before July 21, 1998.

ADDRESSES: Federal Communications Commission, Washington, DC 20554. In addition to filing comments with the FCC, interested parties should serve the petitioner, his counsel, or consultant, as follows: Michael Ruger, Esq., Baker & Hostetler, LLP, 1050 Connecticut Ave., NW., Suite 1100, Washington, DC 20036–5304 (Counsel for Petitioner).

FOR FURTHER INFORMATION CONTACT: Sharon P. McDonald, Mass Media Bureau, (202) 418–2180.

SUPPLEMENTARY INFORMATION: This is a synopsis of the Commission's Notice of Proposed Rule Making, MM Docket No. 98–64, adopted May 6, 1998, and released May 15, 1998. The full text of this Commission decision is available for inspection and copying during normal business hours in the FCC Reference Center (Room 239), 1919 M Street, NW., Washington, DC. The complete text of this decision may also be purchased from the Commission's copy contractor, International Transcription Service, Inc., (202) 857–3800, 1231 20th Street, NW., Washington, DC 20036.

Provisions of the Regulatory Flexibility Act of 1980 do not apply to this proceeding.

Members of the public should note that from the time a Notice of Proposed Rule Making is issued until the matter is no longer subject to Commission consideration or court review, all *ex parte* contacts are prohibited in Commission proceedings, such as this one, which involve channel allotments. See 47 CFR 1.1204(b) for rules governing permissible *ex parte* contacts.

For information regarding proper filing procedures for comments, see 47 CFR 1.415 and 1.420.

List of Subjects in 47 CFR Part 73

Radio broadcasting.

Federal Communications Commission.

John A. Karousos,

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

[FR Doc. 98–13567 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–P

OFFICE OF PERSONNEL MANAGEMENT

48 CFR Part 1609

RIN 3206–AI27

Prohibition of ''Gag Clauses'' in the Federal Employees Health Benefits Program

AGENCY: Office of Personnel Management.

ACTION: Notice of proposed rule making.

SUMMARY: The Office of Personnel Management (OPM) is proposing to amend the regulations to prohibit health benefit carriers participating in the Federal Employees Health Benefits (FEHB) Program from entering into contractual provisions with health care providers or health care workers that would include a provision for incentive payments as an inducement to reduce or limit communication with, or the delivery of health care services to, FEHB enrollees. The rule is intended to ensure providers' and health care workers' ability to communicate with, and advise patients of, any medically necessary treatment options.

DATES: Comments must be received on or before July 20, 1998.

ADDRESSES: Comments should be directed to Abby L. Block, Chief, Insurance Policy and Information Division, OPM, Room 3425, 1900 E Street, NW., Washington, DC 20415–0001.

FOR FURTHER INFORMATION CONTACT: Michael W. Kaszynski, (202) 606–0004.

SUPPLEMENTARY INFORMATION: You may submit comments and data by sending electronic mail (E-mail) to: MWKASZYN@OPM.Gov.

On February 20, 1998, the President signed an Executive Memorandum directing the Office of Personnel Management (OPM) to take the necessary steps to bring the FEHB Program into contractual compliance with the Consumer (Patient) Bill of Rights and Responsibilities by no later than year end 1999. The Memorandum specifically directed OPM to propose regulations within 90 days to prohibit practices that restrict physician-patient communications about medically necessary treatment options. This action will prohibit FEHB participating carriers

from placing incentives in contracts with health care providers or health care workers that would limit providers' or health care workers' ability to discuss medically necessary treatment options with Federal enrollees. We are aware that a proposal to enact a ''gag clause'' regulation raises three broad areas of concern regarding: (1) potential impairment of a health plan's ability to review utilization against appropriate treatment protocols, (2) potential conflict with providers' (including carriers') ethical or moral beliefs, and (3) impact on providers' or workers' ability to discuss non-covered or high cost treatment options. This regulation is not intended to limit a health plan's ability to perform utilization review nor is it intended to cause providers or health care workers to discuss treatment options that they would not ordinarily discuss in their normal course of practice because such options are against their professional judgement and/or ethical, moral or religious beliefs. The regulation will ensure that providers or health care workers have the ability to communicate fully and openly with patients regarding medically necessary treatment options regardless of cost or whether the benefits are covered by their health plan. Simply stated, the amended regulation is intended to remove any contractual impediment to a candid and open physician-patient relationship.

Regulatory Flexibility Act

I certify that this regulation will not have a significant economic impact on a substantial number of small entities because the regulation will only affect health insurance carriers under the Federal Employees Health Benefits Program.

Executive Order 12866, Regulatory Review

This rule has been reviewed by the Office of Management and Budget in accordance with Executive Order 12866.

List of Subjects in 48 CFR Part 1609

Administrative practice and procedure, Government employees, Health facilities, Health insurance, Health professionals, Hostages, Iraq, Kuwait, Lebanon, Reporting and record keeping requirements, Retirement.

Office of Personnel Management.

Janice R. Lachance,

Director.

For the reasons set forth in the preamble OPM proposes to amend 48 CFR Part 1609 as follows:

Subpart 1609.70—Minimum Standards for Health Benefit Carriers

1. The authority citation for 48 CFR Part 1609 continues to read as follows:

Authority: 5 U.S.C. 8913; 40 U.S.C. 486(c); 48 CFR 1.301.

2. In § 1609.7001 new paragraph (c)(7) is added to read as follows:

§ 1609.7001 Minimum Standards for Health Benefits Carriers

* * * * *

(c) * * *

(7) Entering into contracts with providers or health care workers that include incentive plans that directly or indirectly create an inducement to limit communication of, or reduce, medically necessary services to any individual covered under the FEHB Program.

[FR Doc. 98–13782 Filed 5–19–98; 2:20 pm]

BILLING CODE 6325–01–P

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 195

[Docket No. RSPA–97–2095; Notice 1]

RIN 2137–AC11

Pipeline Safety: Adoption of Industry Standards for Breakout Tanks

AGENCY: Research and Special Programs Administration (RSPA),DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: This proposed rule would incorporate industry consensus standards for aboveground storage tanks into the regulations for the transportation of hazardous liquids by pipelines. This action would upgrade the pipeline safety regulations for breakout tanks to the level of the industry standards currently applicable to other steel petroleum tanks at tank farms and refineries throughout the United States. The proposed incorporation of these industry published standards would ensure the safety of breakout tanks used in the transportation of petroleum, petroleum products or anhydrous ammonia.

DATES: RSPA invites interested persons to submit comments by July 20, 1998. Late filed comments will be considered as far as practicable.

ADDRESSES: All commenters should identify the docket number as RSPA–97–2095 and the subject heading as ''Pipeline Safety: Adoption of Industry Standards for Breakout Tanks.'' Written comments should be mailed or delivered to the Docket Facility, U.S. Department of Transportation, Room #PL–401, 400 Seventh Street, SW, Washington, DC 20590–0001. The original and two copies of the comments should be submitted. Persons mailing comments and desiring confirmation of their receipt must include a self-addressed stamped postcard. The Dockets Facility is open from 10:00 a.m. to 5:00 p.m., Monday through Friday, except on Federal holidays when the facility is closed. Comments may also be submitted electronically via e-mail to ops.comments@rspa.dot.gov. Files should be sent in ASCII or text format.

FOR FURTHER INFORMATION CONTACT: Albert C. Garnett, Office of Pipeline Safety (OPS), telephone: (202) 366–2036, FAX: (202) 366–4566, e-mail: albert.garnett@rspa.dot.gov regarding the subject matter of this notice; or the Docket Facility, telephone (800) 647–5527 regarding copies of this notice or other material in the docket.

Comments that have been scanned into the docket may be accessed electronically and read at http://dms.dot.gov. General information about the RSPA/Office of Pipeline Safety programs can be obtained by accessing OPS's internet homepage at http://ops.dot.gov.

SUPPLEMENTARY INFORMATION:

Background

Definition and Regulation of Breakout Tanks

In 49 CFR § 195.2 a breakout tank is defined as a tank used to: (a) relieve surges in a hazardous liquid pipeline system; or (b) receive and store hazardous liquid transported by a pipeline for reinjection and continued transportation by pipeline. Hazardous liquids are defined in 195.2 as: petroleum, petroleum products, or anhydrous ammonia.

Breakout tanks are designed, constructed, operated, and maintained to the same industry standards as other storage tanks throughout the petroleum industry. Consequently, breakout tanks are indistinguishable from other storage tanks that may be located at the same pipeline terminal. They are simply tanks that the operator has assigned to breakout tank functions.

These steel storage tanks are constructed in various configurations, sizes, and material properties to safely contain the liquids and their volatility at the design temperature(s) and pressure(s). Most breakout tanks are aboveground vertical cylindrical tanks that are classified as either atmospheric

tanks or low-pressure tanks. However, liquefied petroleum gas (LPG) may be stored at high-pressures in aboveground tanks with configurations that are more similar to that of ASME Code pressure vessels.

Atmospheric Storage Tanks

Atmospheric storage tanks are those designed to operate their vapor spaces at internal pressures that are approximately atmospheric (vapor pressures not exceeding 2.5 psig). Atmospheric storage tanks are used for commodities such as: crude oil, heavy oils, gas oils, furnace oils, naphtha, gasoline, and nonvolatile chemicals. The roofs of atmospheric storage tanks may take various forms.

An atmospheric cone-roof tank has roof plates that are supported by internal rafters, purlins, columns, and by the top of the cylindrical tank shell. An atmospheric umbrella-roof tank has roof plates formed from curved segments that are completely supported by the top of the cylindrical tank shell. When such fixed roof tanks are fitted with an internal floating roof, the breathing and filling losses are minimized by the elimination of the vapor space above the stored liquid.

Another type of atmospheric tank uses an external floating roof that is also designed to minimize the breathing and filling losses by the elimination of the vapor space above the stored liquid. Occasionally, such an ''open-top'' external floating-roof tank is retrofitted with an aluminum roof that is supported at the top of the cylindrical tank shell. This aluminum fixed roof shields the (former external) floating-roof and the stored hazardous liquid from the adverse effects of severe rainfalls and snowfalls.

Low-Pressure Storage Tanks

Low-pressure tanks are those designed to operate their vapor spaces at internal pressures above 2.5 psig, but not exceeding 15 psig. Low pressure storage tanks are used for commodities such as: light crude oils, some gasoline blending stocks, light naphtha, pentane, and some highly volatile liquids.

There are several designs to withstand the vapor pressure that may develop in low-pressure tanks. Tanks without a device or means to change the internal volume (i.e., vary the vapor space above the stored liquid) have hemispherical, spheroidal, and noded spheroidal configurations to contain the stored liquid and vapor pressure. Other roof designs accommodate the vapor pressure by providing a variable vapor space above the stored liquid. Such tanks are described as breather-roofs, balloon-roofs, and vapor-dome roofs.

High-Pressure Tanks

Breakout tanks used to contain pressures of at least 15 psig are designed in accordance with the ASME Boiler and Pressure Vessel Code, Pressure Vessels, Section VIII, Division 1 and 2. Such pressure tanks with spherical or cylindrical (horizontal) configurations are often used to store highly volatile liquids such as liquefied petroleum gas (LPG). LPG includes propane, propylene, butanes (normal butane and isobutane), and butylenes. Because of their configuration, tanks that store LPG are commonly described as ''spheres'' and ''bullets''.

Number of Breakout Tanks

There are at least 9,000 breakout tanks in the United States. This estimate is based on the results of an ''Aboveground Storage Tank Survey'' conducted for the American Petroleum Institute (API) that were presented in an April 1989 report. In that 1989 report, an estimated 9,197 breakout tanks were calculated to have a total capacity of 556,183,000 barrels. Approximately, 18% were over 100,000 barrels capacity and 71% were estimated to have been constructed since 1948.

Breakout Tank Accident Reporting

Section 195.50 ''Reporting accidents.'' sets out the requirements, including the threshold limits, for accidents to pipelines (includes accidents to breakout tanks) that are to be reported to RSPA by the operator.

Need To Adopt Industry Standards

The failure of a storage tank not associated with pipeline transportation provided much of the incentive to improve industry standards for aboveground steel storage tanks. On January 2, 1988, at a barge terminal in Florefee, Pennsylvania, a newly recommissioned 120 ft. diameter by 48 ft. high storage tank suddenly collapsed and released 3.9 million gallons of diesel oil. Although the earthen dike contained most of the diesel oil, an estimated 750,000 gallons were spilled into the Monongahela River and eventually flowed into the Ohio River. Recovery was estimated at 27.3%.

The publicity and costly consequences of this failure caused widespread concern about the safety of all aboveground storage tanks. Responding to the aftermath of this event, petroleum industry engineers instituted a review of the various industry published standards applicable to aboveground storage tanks. These reviews resulted in considerable updating of existing standards and the development of several new standards by the American Petroleum Institute.

In the 10-year period from 1987–1996, operators of breakout tanks reported 152 accidents to RSPA. These accidents caused no deaths; three injuries to pipeline personnel; $12,422,894 of property damage; and 153,972 barrels to be spilled (of which 39,087 barrels were not recovered). The three injuries occurred as a result of explosions. The causes were reported as: 25 leaks in the tank floor; 30 incorrect operations; 8 outside forces; and 26 malfunctions of control or relief equipment. The remaining 63 were related to problems with floating roof water drain lines, lightning, and miscellaneous other causes.

The pipeline safety regulations have not been revised to reflect the updating and development of new industry standards for aboveground steel storage tanks. Instead, they remain very limited in scope and too general to address many safety-related aspects. For example, in ''Subpart C—Design Requirements'', the design of breakout tanks is set out in a single sentence in § 195.132, which reads: ''Each aboveground breakout tank must be designed to withstand the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.'' This fails to spell out several critical engineering subjects, such as materials, design, fabrication, erection, methods of inspecting joints, welding procedure and welder qualifications, and marking. Moreover, there is no mention of other important topics including foundations, external floating roofs, seismic design, aluminum dome roofs, internal floating roofs, undertank leak detection and subgrade protection, and requirements for operating at elevated temperatures. These topics are covered in detail in API Standard 650—''Welded Steel Tanks for Oil Storage.'' In the pipeline safety regulations for hazardous liquids, similar insufficiencies for breakout tanks exist in ''Subpart D-Construction'', ''Subpart E-Pressure Testing,'' and ''Subpart F-Operation and Maintenance.''

Consequently, RSPA recognizes the need to update the safety regulations for breakout tanks. The most appropriate means of updating is the incorporation by reference into Part 195 of selected industry consensus standards. They are widely understood and have been extensively implemented by the operators of breakout tanks.

Recommendations by Texas Transportation Institute

To obtain professional assistance in the selection of the industry standards to be incorporated into the regulations for breakout tanks, RSPA contracted with the Texas Transportation Institute (TTI) for engineering support services. TTI is associated with Texas A&M University at College Station, Texas. TTI's findings are contained in their report titled—''Engineering Support Services For The Office Of Pipeline Safety (Task 1) July 1997.''

TTI conducted a review of industry publications relating to the aboveground steel storage tanks commonly used at petroleum pipeline terminals. TTI engineers also visited 16 petroleum pipeline terminals in six states. The terminals selected were geographically dispersed in an effort to observe a sampling of the breakout tanks in the contiguous 48 states. The terminals were located in Newark, NJ; Baton Rouge, LA; Tulsa, OK; Houston, Colorado City, Kermit, and McCamey, TX; Long Beach, Morro Bay, Bakersfield and Concord, CA; and Superior, WI.

The 411 storage tanks observed at the 16 terminals had a storage capacity of 47 million barrels. Along with their site-specific observations, the TTI engineers noted that the majority of these breakout tanks were built before 1950 [apparently, these 411 tanks were constructed earlier than the estimated average age of the 9,147 tanks reported under the heading ''Number of Breakout Tanks'' (above)] and that all tanks built before 1936 were riveted. They also reported that the general condition and appearance of the tanks was excellent.

Based on their literature review, discussions with terminal personnel, and personal observations of the breakout tanks, the TTI engineers recommended the incorporation by reference into 49 CFR Part 195 of six API Standards, four API Recommended Practices, and NAPA 30, a Code published by the National Fire Protection Association. RSPA sought the input of storage tank professionals representing the API on these findings.

Pre-Notice Consultation

RSPA provided its stakeholders (i.e. operators of breakout tanks, the petroleum industry and the general public) the opportunity to provide early input on RSPA's intent to incorporate industry standards for storage tanks through a series of meetings:

- On January 29, 1997, in New Orleans, LA, at a public meeting attended by representatives of both the pipeline industry and environmental interests (public and government), a representative of OPS presented the need for updating the breakout tank regulations and announced the industry standards being considered for adoption into 49 CFR Part 195. (Notice of Public Hearing; Response Plans for Onshore Oil Pipelines) (62 FR 2989; January 21, 1997).
- On April 9, 1997, in San Diego, CA, at the 62nd API Spring Refining Meeting, a representative of OPS advised fellow members of the API Subcommittee on Pressure Vessels and Tanks of RSPA's plans to adopt certain API aboveground tank standards and portions of NFPA 30.
- On May 7, 1997, in Washington, DC, at its semi-annual meeting, a representative of OPS made a similar presentation to the Technical Hazardous Liquid Pipeline Safety Standards Committee and to others at the open meeting (Meetings of Pipeline Safety Advisory Committees) (62 FR 16212; April 4, 1997).

Consensus Standards Proposed To Be Incorporated By Reference

RSPA proposes to incorporate nine of the eleven TTI recommendations. Not proposed for adoption is API Standard 2015—''Safe Entry and Cleaning of Petroleum Storage Tanks, Planning and Managing Tank Entry from Decommissioning Through Recommissioning''. Tank cleaning is not covered under the pipeline safety regulations. The potential hazards to personnel and the environment associated with tank cleaning are covered under regulations issued by the Occupational Health and Safety Administration (OSHA) and the Environmental Protection Agency (EPA).

Also, not proposed for adoption is API Standard 2610—''Design, Construction, Operation, Maintenance, and Inspection of Terminal & Tank Facilities''. This standard is a compilation of industry knowledge, information, and management practices for all relevant aspects of terminal and tank operations aggregated into an overview document. It was prepared to be an indexing standard and references some 145 documents that were prepared and published by a myriad of federal and other national and international organizations. Consequently, API Standard 2610 is too complex for inclusion in this rulemaking.

In addition to the nine TTI documents selected, RSPA proposes to incorporate three additional documents: API Specification 12F—''Specification for Shop Welded Tanks for Storage of Production Liquids''; API Publication 2026—''Safe Descent Onto Floating Roofs of Tanks in Petroleum Service''; and API Standard 2510—''Design and Construction of LPG Installations.''

Section 195.3(c) currently lists the full title and edition of 18 publications incorporated by reference in Part 195. Now, this notice would incorporate an additional five API Standards, one API Specification, four API Recommended Practices, one API Publication, and portions of NAPA 30.

API Standards, Specifications, Recommended Practices, Publications and NAPA 30

In the preamble of this notice the term ''standard(s)'' has been used generically to describe certain industry consensus documents developed for aboveground steel petroleum storage tanks. More specifically, the API standards selected for incorporation by reference have been classified by API as Standards, Specifications, Recommended Practices, and Publications. Similarly, NFPA 30 has been classified by the NFPA as a Code. RSPA understands that these classifications have been chosen to indicate the varying levels of prescriptiveness intended by the publishers.

This proposal attempts to follow the intended level of prescriptiveness between these Standards, Specifications, Codes, Recommended Practices, and Publications. However, this proposal provides clarification necessary for incorporation into Federal rules. Accordingly, for this rulemaking, operators of breakout tanks would be expected to comply with these industry classifications as follows:

- Standard, Specification or Code—An operator would be expected to comply with the provisions as though they were printed in full in Part 195.
- Recommended Practice—An operator would be expected to follow the provisions unless the operator notes in the procedural manual the reasons why compliance with all or certain provisions is not necessary for the safety of a particular breakout tank or tanks.
- Publication—These provisions provide guidelines, safety practices and precautions for the operator's review and consideration for inclusion in the procedural manual.

Documents [1] To Be Incorporated by Reference

1. API SPECIFICATION 12F—Specification for Shop Welded Tanks for Storage of Production Liquids, Eleventh Edition, November 1, 1994.

This specification covers materials, design, fabrication, and testing requirements for aboveground shop-fabricated vertical, cylindrical, closed top, welded steel breakout tanks for nominal capacities of 90 to 750 barrels and internal pressures that are approximately atmospheric.

This specification is designed to provide tanks for use in the storage of crude petroleum and other liquids commonly handled and stored by the oil production segment of the industry. [However, these storage tanks are occasionally located on crude oil pipeline systems and a few are known to be breakout tanks.]

This specification contains Appendices A through F. Appendix A discusses tank bolting. Appendix B discusses normal venting. Appendix C discusses emergency venting. Appendix D discusses walkways, stairways and ladders. Appendix E discusses details of purchase order with the manufacturer. Appendix F discusses the use of the API Monogram.

2. API STANDARD 620—Design and Construction of Large, Welded, Low-Pressure Storage Tanks, Ninth Edition, February 1996 (Including Addenda 1 and 2)

This standard covers materials, design, fabrication, inspection and testing, marking and pressure- and vacuum-relieving devices for large, welded, low pressure carbon steel aboveground storage tanks (including flat-bottom tanks) that have wall shapes that can be generated by a contour around a single vertical axis of revolution. This standard is applicable to tanks that are intended to: (a) hold or store liquids with gases or vapors above their surface; or (b) hold or store gases or vapors alone.

The tanks described in this standard are designed for metal temperatures not greater than 250°F and with pressures in their gas or vapor spaces not more than 15 psig. This standard is applicable to tanks installed in areas where the lowest recorded one-day mean atmospheric temperature is -50°F. [Although tanks designed to this standard are more commonly found in other petroleum facilities, a few are located on pipeline systems and known to be breakout tanks.]

The standard contains Appendices A through R. Appendix A discusses definitions. Appendix B discusses use of materials not identified with listed specifications. Appendix C discusses suggested practice regarding foundations. Appendix D discusses suggested practice regarding supporting structures. Appendix E discusses suggested practice regarding attached structures (internal & external). Appendix F discusses examples illustrating application of rules to various design problems. Appendix G discusses considerations regarding corrosion allowance and hydrogen-induced cracking. Appendix H discusses recommended practice for use of preheat, post-heat, and stress relief. Appendix I discusses suggested practice for peening. Appendix J discusses technical inquiries. Appendix K discusses the suggested practice for determining the relieving capacity required. Appendix L discusses seismic design. Appendix M discusses recommended scope of manufacturer's report. Appendix N discusses installation of pressure-relieving devices. Appendix O discusses suggested practice regarding installation of low-pressure tanks. Appendix P is blank and reserved for future use. Appendix Q discusses low-pressure storage tanks for liquefied hydrocarbon gases at temperatures between −60°F and −270°F. Appendix R discusses low-pressure storage tanks for refrigerated products at temperatures from +40°F to −60°F.

3. API STANDARD 650—Welded Steel Tanks for Oil Storage, Ninth Edition, May 1993 (Including Addenda 1 through 4)

This standard covers material, design, fabrication, erection (including inspection, testing & repairs), inspecting joints, welding procedure and welding qualifications, and marking for vertical, cylindrical, aboveground, closed- and open-top, welded steel storage tanks in various sizes and capacities for internal vapor or gas pressures approximating atmospheric pressure (not greater than 2.5 psig or not exceeding the weight of the roof plates), except when designed for tanks subject to seismic loading. This standard applies only to tanks whose entire bottoms are uniformly supported and to tanks in nonrefrigerated service that have a maximum operating temperature of 200°F.

This standard contains Appendices A through P and Appendix S. Appendix A discusses optional design for small tanks. Appendix B discusses design and construction of foundations. Appendix C discusses external floating roofs. Appendix D discusses submission of technical inquiries. Appendix E discusses seismic design. Appendix F discusses design for small internal pressures. Appendix G discusses structurally supported aluminum dome roofs. Appendix H discusses internal floating roofs. Appendix I discusses undertank leak detection and subgrade protection. Appendix J discusses complete shop assembly of vertical tanks not exceeding 20 feet in diameter. Appendix K discusses variable-design-point method. Appendix L discusses data sheets for purchaser when ordering and manufacturer when completing construction. Appendix M discusses requirements for tanks operating at temperatures 200°F to 500°F. Appendix N discusses use of new or unused materials not completely identified. Appendix O discusses under-bottom connections. Appendix P discusses allowable external loads on tank shell openings. Appendix S discusses austenitic stainless steel storage tanks.

4. API RECOMMENDED PRACTICE 651—Cathodic Protection of Aboveground Petroleum Storage Tanks, Second Edition, Dec. 1997

The purpose of this recommended practice is to present procedures and practices for achieving effective corrosion control on aboveground storage tank bottoms through the use of cathodic protection. It contains provisions for the application of cathodic protection to new and existing storage tanks. Corrosion control methods based on chemical control of the environment or the use of protective coatings are not covered in detail.

The intent is to provide information and guidance specific to aboveground steel storage tanks in hydrocarbon service. Specific cathodic protection designs are not provided. Such designs should be provided by a person thoroughly familiar with cathodic protection practices.

5. API RECOMMENDED PRACTICE 652—Lining of Aboveground Petroleum Storage Tank Bottoms, Second Edition, December 1997

This recommended practice presents procedures and practices for achieving effective corrosion control in aboveground storage tanks by application of tank bottom linings to both existing and new storage tanks. In many cases, tank bottom linings have proven to be an effective method of

[1] The descriptions of these documents are excerpted from material in the introductory paragraphs and other parts and appendices of the listed documents. They do not summarize all the provisions in these documents.

preventing internal corrosion of steel tank bottoms.

The intent of this recommended practice is to provide information and guidance specific to aboveground steel storage tanks in hydrocarbon service. It is intended to serve only as a guide and detailed tank bottom specifications are not included.

6. API STANDARD 653—Tank Inspection, Repair, Alteration, and Reconstruction, Second Edition, December 1995 (Including Addenda 1 and 2)

This standard covers carbon and low alloy steel tanks built to API Standard 650 or its predecessor Standard 12C. It provides minimum requirements for maintaining the integrity of welded or riveted, non-refrigerated, atmospheric pressure, aboveground storage tanks after they have been placed in service. It covers the maintenance inspection, repair, alteration, relocation and reconstruction of such tanks. It discusses tank evaluation, brittle fracture considerations, inspection, materials, design considerations for reconstruction, repair and alteration, dismantling and reconstruction, examination and testing, marking and record keeping.

The scope is limited to the tank foundation, bottom, shell, structure, roof, attached appurtenances, and nozzles to the face of the first flange, first threaded joint, or first welding-end connection. Many of the design, welding, examination, and material requirements of API Standard 650 can be applied in the maintenance inspection, rating, repair, and alteration of in-service tanks. In case of an apparent conflict between the requirements of API standard 653 and API Standard 650 or its predecessor Standard 12C, this standard shall govern for tanks that have been placed in service.

This standard employs the principles of API Standard 650. However, storage tank owners/operators, based on consideration of specific construction and operating details, may apply this standard to any steel tank constructed in accordance with a tank specification.

This standard covers the varied conditions which may occur in an existing tank. When design and construction details are not given, and are not available in the standard to which the tank was originally constructed, then details that will provide a level of integrity equal to the level provided by the current edition of API Standard 650 must be used.

This standard contains Appendices A through E. Appendix A provides a table listing past editions of API welded storage tank standards. Appendix B discusses evaluation of tank bottom settlement. Appendix C provides sample checklists for internal and external inspection of tanks. Appendix D provides information and forms relating to the API Authorized Inspector Certification Program. Appendix E discusses the procedure for submission of technical inquiries.

7. API STANDARD 2000—Venting Atmospheric and Low-Pressure Storage Tanks, Fourth Edition, September 1992

This standard covers the normal and emergency venting requirements for liquid petroleum or petroleum products storage tanks and aboveground and underground refrigerated storage tanks designed for operation at pressures from vacuum through 15 psig (1.034 bar gauge). Discussed in this standard are the causes of overpressure or vacuum, determination of venting requirements, means of venting, selection, installation, and maintenance of vents, and testing and marking of relief devices. Detailed engineering studies of a particular tank and its operating conditions may indicate that the appropriate venting capacity for the tank is not the venting capacity estimated in accordance with this standard. If a tank's operating conditions could deviate from those used in developing this standard, detailed engineering studies should be performed.

This standard contains Appendices A through C. Appendix A discusses thermal venting and oil movement venting. Appendix B discusses the basis of the emergency venting tables. Appendix C discusses the types and operating characteristics of vents.

8. API RECOMMENDED PRACTICE 2003—Protection Against Ignitions Arising out of Static, Lightning, and Stray Currents, Fifth Edition, December 1991

This recommended practice presents the current technology in the fields of static electricity, lightning, and stray currents applicable to the prevention of hydrocarbon ignition. The recommendations for protection are based on research and practical experience in the petroleum industry. Their use should lead to improved safety practices and evaluations of existing installations and procedures.

This recommended practice contains Appendices A through D. Appendix A discusses the fundamentals of static electricity. Appendix B discusses the measurement and detection of static electricity. Appendix C is a static ignition questionnaire developed to permit recording and transmittal of circumstances involved in an ignition from static electricity. Appendix D is a bibliography supporting restrictions given in the text.

9. API PUBLICATION 2026—Safe Access/Egress Involving Floating Roofs of Storage Tanks in Petroleum Service, Second Edition, April 1998

This publication addresses the hazards associated with access/egress onto open-top, covered open-top and internal floating roofs of in-service petroleum storage tanks and identifies some of the most common practices and procedures for safely accomplishing this activity.

This publication is intended primarily for those persons who are required to perform inspection, service, maintenance or repair activities that involve descent onto floating roofs of in-service petroleum tanks.

This publication does not cover general considerations that apply to climbing onto petroleum storage tanks and other structures, including, but not limited to: (a) slippery or ice-covered stairways and walkways, (b) access during electrical storms, and (c) access during emergency conditions (such as to extinguish a fire or cover exposed product with foam). This publication may not apply to daily or routine tasks of tank gaugers and other personnel involved in non-permit confined spaces; however, such persons shall be trained and shall be made aware of the potential hazards described herein.

Preparations and precautions for entering petroleum storage tanks that have been removed from service for cleaning are covered in API Standard 2015.

10. API RECOMMENDED PRACTICE 2350—Overfill Protection for Storage Tanks in Petroleum Facilities, Second Edition, Jan. 1996

Preventing petroleum storage tanks from being overfilled is an important safety and environmental concern. The safe operation of a petroleum storage facility is dependent upon the receipt of product into the intended storage tank within its defined capacity. Aboveground storage tank overfills can be effectively reduced by developing and implementing practical and safe operating procedures for storage facilities and by providing for careful selection of equipment, scheduled maintenance programs, and employee training.

Recognizing the need for flexibility, this recommended practice covers both manual procedures and automatic

systems that can be used to protect against overfills.

This recommended practice contains Appendices A through C. Appendix A discusses overfill protection system installation. Appendix B discusses determination of tank capacity and product levels. Appendix C discusses overfill protection equipment.

11. API STANDARD 2510—Design and Construction of LPG Installations, Seventh Edition, May 1995.

This standard is written to cover the design, construction, and location of liquefied petroleum gas (LPG) installations at pipeline terminals, tank farms, and at other facilities specified in the standard. The standard is written for LPG tanks with pressures in their gas or vapor spaces greater than 15 psig.

However, for the purposes of this rulemaking only the sections relating to: the design and construction of LPG tanks; spill containment; tank foundations and supports; and tank accessories including pressure-and vacuum-relieving devices, are proposed for incorporation by reference into Part 195.

This standard is not intended to apply to the design, construction, or relocation of frozen earth pits, underground storage caverns or wells, underground or mounded storage tanks, and aboveground concrete storage tanks. Moreover, this standard also is not intended to apply to the following installations:

a. Those covered by API Standard 2508—''Design and Construction of Ethane and Ethylene Installations at Marine and Pipeline Terminals, Natural Gas Processing Plants, Refineries, Petrochemical Plants, and Tank Farms''. [API lists this standard as Out-of-Print.]

b. Those covered by NFPA 58—''Storage and Handling of Liquefied Petroleum Gases'; and NFPA 59—''Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants''.

c. U.S. Department of Transportation (DOT) containers.

d. Gas utility company facilities; refinery equipment; gas processing equipment; and transfer systems from process equipment before LPG storage.

e. Tanks with less than 2,000 gallons of storage capacity.

This standard contains Appendix A. Appendix A discusses Piping, Valves, Fittings, and Optional Equipment.

12. NFPA 30—Flammable and Combustible Liquids Code, 1996 Edition.

NFPA Code 30 applies to the storage, handling and use of flammable liquids and combustible liquids. Such liquids are defined and classified in Chapter 1 ''General Provisions''. In Section 1–7.3.1 ''Flammable Liquids'', liquids are classified as ''Class I liquids'' by laboratory procedures that determine their closed-cup flash point and their Reid vapor pressure. In Section 1–7.3.1 such ''Class I liquids'' may be further classified as Class IA liquids, Class IB liquids, or Class IC liquids.

In Chapter 2 ''Tank Storage'', Section 2–3.4.3 applies to impounding around tanks by diking. In this section the impounded liquids are identified as ''Class I liquids''. Although the great majority of hazardous liquids stored in breakout tanks are ''Class I liquids'', that term is not used in part 195. Therefore, for the purposes of adopting Section 2–3.4.3 into part 195, the term ''Class I liquids'' must be replaced by ''hazardous liquids'.

Section 2–3.4.3 Impounding Around Tanks by Diking

Describes the protection of adjoining property or waterways by diking around aboveground storage tanks.

Section 2–3.4.2 Remote Impounding

Describes the protection of adjoining property or waterways by drainage to a remote impounding area, so that the impounded liquid will not be held against the aboveground storage tanks.

Regulatory Analyses and Notices

A. Executive Order 12866 and DOT Regulatory Policies and Procedures

The Department of Transportation (DOT) does not consider this action to be a significant regulatory action under Section 3(f) of Executive Order 12866 (58 FR 51735; October 4, 1993) and was not reviewed by the Office of Management and Budget. DOT does not consider this action significant under DOT's regulatory policies and procedures (44 FR 11034; February 26, 1979).

This NPRM would amend the regulations for breakout tanks to include the incorporation by reference of certain of the latest industry published standards for aboveground storage tanks. The adoption of industry standards is consistent with the President's goal of regulatory reinvention and improvement of customer service to the American people. There is minimal or no cost for operators of breakout tanks to comply with this rule because these consensus standards have been developed and implemented by industry organizations to ensure the safety of aboveground petroleum storage tanks.

The proposed standards for steel storage tanks were specifically developed by the API. API is the major petroleum industry trade organization and many of its members are operators of petroleum pipelines with tank farms. Additionally, the proposed standard for secondary containment is taken from an NFPA code that is a widely used industry standard for the design of diking (containment by impounding) for aboveground storage tanks. The NFPA is an association with a membership of more than 67,000 individuals and over 100 national trade and professional organizations. Its mission is to reduce the burden of fire on the quality of life by advocating scientifically based consensus codes and standards, research, and education for fire and safety issues.

The operators of breakout tanks storing hazardous liquids are very familiar with these API storage tank and NFPA diking standards because they have been extensively implemented at pipeline terminals throughout the United States. Conversations with an industry storage tank organization representing medium and smaller operators of breakout tanks confirm that most of their members are already complying with the proposed tank standards. Because the economic impact of this proposal is minimal, the incorporation by reference of these industry published standards does not warrant preparation of a Regulatory Evaluation.

For several years, OMB Circular A–119, ''Federal Participation in the Development and Use of Voluntary Standards'', encouraged, but did not require, agencies to participate in consensus standards bodies and to adopt voluntary consensus standards whenever possible. The National Technology Transfer and Advancement Act of 1995 (NTTAA, Pub. L. 104–113) codified and expanded the participation and reporting requirement of OMB Circular A–119. Federal agencies and departments are now required to use technical standards that are developed and adopted by voluntary consensus bodies, where practicable. RSPA's proposed adoption of the API and NFPA standards for petroleum storage tanks meets the goals and requirements set forth in both OMB Circular A–119 and NTTAA.

B. Regulatory Flexibility Act

As discussed above, RSPA is proposing the incorporation of consensus standards that were developed and published by authoritative organizations associated with the petroleum industry. Consequently, these safety standards are well known and have been

implemented by operators of aboveground storage tanks at hazardous liquid pipeline terminals throughout the United States. RSPA has had conversations with an operators' association representing these tank farms and with other persons and those parties do not expect this proposal to have a significant economic impact on the smaller operators of breakout tanks. Nonetheless, RSPA is particularly interested in receiving comments from any small business operators believing otherwise.

Moreover, in the event that some operators of breakout tanks have not yet implemented all the safety-related items in these industry developed standards, the regulations proposed in this notice would allow operators 18 months for compliance after the date of publication the final rule.

Therefore, based on the facts available which indicate the anticipated minimal impact of this rulemaking action, I certify, pursuant to Section 605 of the Regulatory Flexibility Act (5 U.S.C. 605), that this rulemaking action will not have a significant economic impact on a substantial number of small entities.

C. Federal Assessment

The proposed rulemaking action would not have substantial direct effects on states, on the relationship between the federal government and the states, or on the distribution of power and responsibilities among the various levels of government. Therefore, in accordance with the Executive Order 12612 (52 FR 41685; Oct. 30, 1987), RSPA has determined that the action does not have sufficient federalism implications to warrant preparation of a Federalism Assessment.

D. Unfunded Mandates

This proposed rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of over $100 million or more to either state, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the rule.

E. Paperwork Reduction Act

The proposed API Standard 653 includes sample checklists, provided for the operators periodic inspection of welded or riveted, non-refrigerated, atmospheric pressure, aboveground steel storage tanks. The checklists identify the tank components and auxiliary items that should be considered for inspection and provides blank spaces for insertion of the inspection date and notation of the inspector's comments (if any). The use of the checklists improves the effectiveness and minimizes the paperwork burden associated with the existing inspection requirements in 49 CFR Section 195.432. This API standard has been published for several years and during that time it has been available to all operators of petroleum storage tanks (i.e. refinery, marketing, production and pipeline).

For the API Recommended Practices referred to in this rulemaking, it is stated that the operator would be expected to follow the provisions unless the operator notes in the procedural manual the reasons why compliance with all or certain provisions is not necessary for the safety of a particular breakout tank or tanks. Each operator's procedural manual already requires the inclusion and updating of similar safety-related procedures and practices, so that such annotation is consistent with the long standing function of the procedural manual. Moreover, most operators already follow the API Recommended Practices that are proposed for adoption and would not need to make such an annotation in the procedural manual.

Therefore, there is no additional burden and no paperwork analysis is required for this proposal.

List of Subjects in 49 CFR Part 195

Carbon dioxide, Incorporation by reference, Hazardous liquids, Petroleum, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, RSPA proposes to amend Part 195 of title 49 of the Code of Federal Regulations as follows:

PART 195—TRANSPORTATION OF HAZARDOUS LIQUIDS BY PIPELINE [AMENDED]

1. The authority citation for Part 195 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60118; and 49 CFR 1.53.

2. Section 195.3 would be amended by adding paragraphs (b)(7),(c)(2)(iv) through (c)(2)(xiv), and (c)(6) and revising paragraph (c)(3)(v) to read as follows:

§ 195.3 Matter incorporated by reference.

* * * * *

(b) * * *

(7) National Fire Protection Association (NFPA), 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269–9101.

(c) * * *

(2) * * *

(iv) API Specification 12F ''Specification for Shop Welded Tanks for Storage of Production Liquids'' (Eleventh Edition, November 1, 1994).

(v) API Standard 620 ''Design and Construction of Large, Welded, Low-Pressure Storage Tanks'' (Ninth Edition, February 1996, Including Addenda 1 and 2).

(vi) API Standard 650 ''Welded Steel Tanks for Oil Storage'' (Ninth Edition, February 1996 (Including Addenda 1 through 4).

(vii) API Recommended Practice 651 ''Cathodic Protection of Aboveground Petroleum Storage Tanks'' (Second Edition, Dec. 1997).

(viii) API Recommended Practice 652 ''Lining of Aboveground Petroleum Storage Tanks Bottoms'' (Second Edition, December 1997).

(ix) API Standard 653 ''Tank Inspection, Repair, Alteration, and Reconstruction'' (Second Edition, December 1995 (Including Addenda 1 and 2).

(x) API Standard 2000 ''Venting Atmospheric and Low-Pressure Storage Tanks'' (Fourth Edition, September 1992).

(xi) API Recommended Practice 2003 ''Protection Against Ignitions Arising out of Static, Lightning, and Stray Currents' (Fifth Edition, December 1991).

(xii) API Publication 2026 ''Safe Access/Egress Involving Floating Roofs of Storage Tanks in Petroleum Service'' (Second Edition, April 1998).

(xiii) API Recommended Practice 2350 ''Overfill Protection for Storage Tanks In Petroleum Facilities'' (Second Edition, January 1996).

(xiv) API Standard 2510 ''Design and Construction of LPG Installations'' (Seventh Edition, May 1995).

* * * * *

(3) * * *

(v) ASME Boiler and Pressure Vessel Code, Section VIII ''Pressure Vessels,'' Division 1 and 2. (1995 edition with 1995 Addenda).

* * * * *

(6) National Fire Protection Association (NFPA):

(i) ANSI/NFPA 30 ''Flammable and Combustible Liquids Code,'' (1996).

(ii) [Reserved]

3. Section 195.132 would be revised to read as follows:

§ 195.132 Design and construction of breakout tanks.

(a) Breakout tanks must be designed and constructed to withstand the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.

(b) For aboveground breakout tanks first placed in service on or after [18

months after date of publication of final rule], compliance with paragraph (a) of this section requires one of the following:

(1) Shop-fabricated, vertical, cylindrical, closed top, welded steel tanks with nominal capacities of 90 to 750 barrels (14.3 to 119.2 m^3) and internal pressures that are approximately atmospheric must be designed and constructed in accordance with API Specification 12F.

(2) Welded, low-pressure (i.e., internal vapor space not greater than 15 psig (103.4 kPa)), carbon steel tanks that have wall shapes that can be generated by a single vertical axis of revolution must be designed and constructed in accordance with API Standard 620.

(3) Vertical, cylindrical, welded steel tanks with pressures approximating atmospheric pressures (i.e., internal vapor pressures not greater than 2.5 psig (17.2 kPa), or not greater than the weight of the roof plates) must be designed and constructed in accordance with API Standard 650.

(4) High pressure steel tanks (i.e., pressures in their gas or vapor space greater than 15 psig (103.4 kPa)) with a nominal capacity of 2000 gallons (7571 liters) or more of liquefied petroleum gas (LPG) must be designed and constructed in accordance with API Standard 2510.

4. Section 195.205 would be added to read as follows:

§ 195.205 Repair, alteration and reconstruction of breakout tanks that have been in service.

(a) Breakout tanks that have been repaired, altered, or reconstructed and returned to service must be capable of withstanding the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads.

(b) On or after [18 months after date of publication of final rule], compliance with paragraph (a) of this section requires the following for the aboveground breakout tanks specified:

(1) For atmospheric pressure tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and others (such as those built to API Standard 650 or its predecessor Standard 12C), repair, alteration, and reconstruction must be in accordance with API Standard 653.

(2) For tanks built to API Specification 12F, API Standard 620, or API Standard 2510, the repair, alteration, and reconstruction, must be in accordance with those respective standards.

5. Section 195.242 would be amended by adding paragraphs (c) and (d) to read as follows:

§ 195.242 Cathodic protection system.

* * * * *

(c) For the bottoms of aboveground breakout tanks, with greater than 500 barrels (79.5 m^3) capacity, built to API Specification 12F, API Standard 620, and others (such as API Standard 650 or its predecessor Standard 12C), the installation of a cathodic protection system under paragraph (a) of this section on or after [18 months after date of publication of final rule] must be in accordance with API Recommended Practice 651, unless the operator notes in the procedural manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of a particular breakout tank.

(d) For the internal bottom of aboveground breakout tanks, built to API Specification 12F, API Standard 620 and others (such as API Standard 650 or its predecessor Standard 12C), the installation of a tank bottom lining on or after [18 months after date of publication of final rule] must be in accordance with API Recommended Practice 652, unless the operator notes in the procedural manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 652 is not necessary for the safety of a particular breakout tank.

6. Section 195.264 would be revised to read as follows:

§ 195.264 Secondary containment, protection against entry, normal/emergency venting or pressure/vacuum relief for aboveground breakout tanks.

(a) A means must be provided for containing hazardous liquids in the event of spillage or failure of an aboveground breakout tank.

(b) On or after [18 months after date of publication of final rule], compliance with paragraph (a) of this section requires the following for the aboveground breakout tanks specified:

(1) For tanks built to API Specification 12F, API Standard 620, and others (such as API Standard 650 or its predecessor Standard 12C), the installation of secondary containment must be in accordance with the following sections of NFPA 30:

(i) Secondary containment by impounding around a breakout tank must be installed in accordance with Section 2–3.4.3 ''Impounding around Tanks by Diking'', except that ''hazardous liquids'' must be substituted for the term ''Class I liquids'' wherever that term appears in Section 2–3.4.3; and

(ii) Secondary containment by drainage to a remote impounding area must be installed in accordance with Section 2–3.4.2 ''Remote Impounding.''

(2) For tanks built to API Standard 2510, the installation of secondary containment must be in accordance with Sections 3 or 9 of API Standard 2510.

(c) Breakout tank areas must be adequately protected against unauthorized entry.

(d) Normal/emergency relief venting must be provided for each atmospheric pressure breakout tank. Pressure/vacuum-relieving devices must be provided for each low-pressure and high-pressure breakout tank.

(e) For normal/emergency relief venting and pressure/vacuum-relieving devices installed on aboveground breakout tanks on or after [18 months after date of publication of final rule], compliance with paragraph (d) of this section requires the following for the tanks specified:

(1) Normal/emergency relief venting installed on atmospheric pressure tanks built to API Specification 12F must be in accordance with Section 4, and Appendices B and C, of API Specification 12F.

(2) Normal/emergency relief venting installed on atmospheric pressure tanks (such as those built to API Standard 650 or its predecessor Standard 12C) must be in accordance with API Standard 2000.

(3) Pressure-relieving and emergency vacuum-relieving devices installed on low pressure tanks built to API Standard 620 must be in accordance with Section 7 of API Standard 620 and its references to the normal and emergency venting requirements in API Standard 2000.

(4) Pressure and vacuum-relieving devices installed on high pressure tanks built to API Standard 2510 must be in accordance with Sections 5 or 9 of API Standard 2510.

7. Section 195.305 would be added to read as follows:

§ 195.305 Pressure testing breakout tanks.

(a) For breakout tanks built to API Specification 12F and first placed in service on or after [18 months after date of publication of final rule], pneumatic testing must be in accordance with Section 5.3 of API Specification 12F.

(b) For breakout tanks built to API Standard 620 and first placed in service on or after [18 months after date of publication of final rule], hydrostatic and pneumatic testing must be in accordance with Section 5.18 of API Standard 620.

(c) For breakout tanks built to API Standard 650 and first placed in service

on or after [18 months after date of publication of final rule], hydrostatic and pneumatic testing must be in accordance with Section 5.3 of API Standard 650.

(d) For atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and others (such as those that were built to API Standard 650 or its predecessor Standard 12C), that are returned to service on or after [18 months after date of publication of final rule], the necessity for the hydrostatic testing of repair, alteration, and reconstruction is covered in Section 10.3 of API Standard 653.

(e) For breakout tanks built to API Standard 2510 and first placed in service on or after [18 months after date of publication of final rule], pressure testing must be in accordance with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or 2.

8. Section 195.405 would be added to read as follows:

§ 195.405 Protection against ignitions and safe access/egress involving floating roofs.

(a) Protection provided on or after [18 months after date of publication of final rule] against ignitions arising out of static electricity, lightning, and stray currents during operation and maintenance activities involving aboveground breakout tanks, must be in accordance with API Recommended Practice 2003, unless the operator notes in the procedural manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 2003 is not necessary for the safety of a particular breakout tank.

(b) The hazards associated with access/egress onto floating roofs of in-service breakout tanks to perform inspection, service, maintenance or repair activities (other than specified general considerations, specified routine tasks or entering tanks removed from service for cleaning) are addressed in API Publication 2026. On or after [18 months after date of publication of final rule] the operator must review and consider the potentially hazardous conditions, safety practices and procedures in API Publication 2026 for inclusion in the procedure manual (§ 195.402(c)).

9. Section 195.416 would be amended by adding paragraph (j) to read as follows:

§ 195.416 External corrosion control.

* * * * *

(j) For breakout tanks where corrosion of the tank bottom is controlled by a cathodic protection system, the cathodic protection system must be inspected to ensure it is operated and maintained in accordance with API Recommended Practice 651, unless the operator notes in the procedure manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 651 is not necessary for the safety of a particular breakout tank.

10. Section 195.428 would be amended by revising the title and by adding paragraphs (c), (d) and (e) to read as follows:

§ 195.428 Overpressure safety devices and overfill protection systems.

* * * * *

(c) Except as provided in paragraph (d) of this section, aboveground breakout tanks must have an overfill protection system in accordance with API Recommended Practice 2350, on or after [18 months after date of publication of final rule], unless the operator notes in the procedural manual (§ 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 2350 is not necessary for the safety of a particular breakout tank. However, API Recommended Practice 2350 does not apply to tanks with less than 600 gallons (2271 liters) of storage capacity.

(d) Breakout tanks that were built to API Standard 2510 must have an overfill protection system in accordance with Section 5.1.2 of API Std. 2510 on or after [18 months after date of publication of final rule].

(e) The inspection and testing of each overfill protection system on or after [18 months after date of publication of final rule] must be in accordance with the requirements for inspection and testing of pressure control equipment in paragraphs (a) and (b) of this section.

11. Section 195.432 would be revised to read as follows:

§ 195.432 Inspection of in service Breakout tanks.

(a) Each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each breakout tank (including atmospheric and pressure tanks).

(b) On or after [18 months after date of publication of final rule], compliance with paragraph (a) of this section for the inspection of the breakout tanks specified requires the following:

(1) For tanks that are constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated (such as atmospheric tanks built to API Standard 650 or its predecessor Standard 12C), the integrity inspection must be in accordance with Section 4 of API Standard 653.

(2) [Reserved].

Issued in Washington, DC on May 15, 1998.

Richard B. Felder,

Associate Administrator for Pipeline Safety.

[FR Doc. 98–13579 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–60–P

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

49 CFR Part 575

[Docket No. NHTSA–97–3251]

RIN 2127–AG67

Consumer Information Regulations; Uniform Tire Quality Grading Standards

AGENCY: National Highway Traffic Safety Administration (NHTSA), Department of Transportation.

ACTION: Notice of proposed rulemaking.

SUMMARY: This rulemaking action follows the agency's granting of a petition filed by the Association of International Automobile Manufacturers (AIAM) for rulemaking to amend the Uniform Tire Quality Grading Standards (UTQGS) to remove the requirement that vehicle manufacturers provide general UTQGS information to purchasers and potential purchasers at the point of sale of new motor vehicles. That information is normally provided in leaflets that inform customers of the existence of the UTQGS, explain their purpose, and explain how consumers can use UTQGS information in purchasing replacement tires for passenger motor vehicles. Because new passenger cars are typically equipped with tires from any one of a number of tire manufacturers, the leaflets do not contain any information on the tires provided on a specific vehicle.

Pursuant to the AIAM petition, the agency proposes to amend the consumer information regulation by removing the requirement that motor vehicle manufacturers provide general UTQGS information to purchasers and prospective purchasers of new motor vehicles at the point of sale, requiring instead that such information be included in owners' manuals, as some auto manufacturers already do. Elimination of the point-of-sale requirement would remove a burden on motor vehicle manufacturers and dealers, yet should have little effect on consumers. NHTSA believes that the general UTQGS information is of little value to consumers at the point of sale of new vehicles because the vehicles are sold with tires selected by the

manufacturer and the consumer has limited, if any, choice in selecting tire brands and models. Further, consumers normally have little interest in replacement tires when shopping for or purchasing a new vehicle. The agency believes that consumers would be better served by requiring such information to be included in owners' manuals for the future reference of those consumers when purchasing replacement tires. Finally, this action also proposes to delete the definitions of *brake power unit, lightly loaded vehicle weight, maximum loaded vehicle weight,* and *maximum sustained vehicle speed* from part 575 because they are no longer pertinent to the Consumer Information Regulations.

DATES: Comment closing date: Comments on this notice must be received on or before July 20, 1998.

Proposed effective date: If adopted, the amendments proposed herein would become effective for new motor vehicles introduced more than 180 days following publication of the final rule in the **Federal Register**. Optional early compliance would be permitted beginning on the date of publication of the final rule in the **Federal Register**.

ADDRESSES: Comments should refer to the docket number noted above and be submitted to: Docket Management, Room PL–401, 400 Seventh Street SW, Washington, DC 20590. Docket room hours are from 10 a.m. to 5 p.m., Monday through Friday.

FOR FURTHER INFORMATION CONTACT: *For technical issues,* Mr. P.L. Moore, Safety Standards Engineer, Office of Planning and Consumer Programs, Safety Performance Standards, National Highway Traffic Safety Administration, 400 Seventh Street SW, Washington, DC 20590, telephone (202) 366–5222.

For legal issues: Walter K. Myers, Attorney-Advisor, Office of the Chief Counsel, National Highway Traffic Safety Administration, 400 Seventh Street SW, Washington, DC 20590; telephone (202) 366–2992.

SUPPLEMENTARY INFORMATION:

Background

Section 30123(e) of Title 49, U.S. Code requires the Secretary of Transportation to prescribe a uniform quality grading system for motor vehicle tires. The purpose of such system is to assist consumers in making informed decisions when purchasing tires.

Authority to implement that requirement was delegated to the Administrator of NHTSA. In accordance with that statutory mandate, NHTSA issued the UTQGS in 49 Code of Federal Regulations (CFR), § 575.104. The UTQGS, applicable to new passenger car tires, in general require motor vehicle and tire manufacturers and tire brand name owners to provide consumers with grading information for each tire of which they are the manufacturer or brand name owner with respect to their tires' relative performance regarding treadwear, traction, and temperature resistance. Excluded from the standards are deep tread, winter-type snow tires, space-saver or temporary-use spare tires, tires with nominal rim diameters of 10 to 12 inches, and limited production tires.

Section 575.6(a) of Title 49, CFR requires that at the time a motor vehicle is delivered to the first purchaser for purposes other than resale, the manufacturer of that vehicle must provide, in writing and in the English language, the information specified in §§ 575.103 and 575.104 that is applicable to the vehicle and its tires. The required information regarding tires is set forth in § 575.104(d)(1)(iii) which requires the vehicle manufacturer to list all possible grades for traction and temperature resistance and restate verbatim the explanation for each of the three performance areas. The information must also contain a statement referring the reader to the tire sidewall for the specific tire grades for the tires with which the vehicle is equipped. In addition, § 575.6(c) requires each manufacturer of motor vehicles, each brand name owner of tires, and each manufacturer of tires for which there is no brand name owner to provide the information specified in subpart B of part 575 [1] to prospective purchasers at each location at which its vehicles or tires are offered for sale. The subpart B information pertaining to tires specified in § 575.104(d)(1)(ii) is also the general information on tire grading with additional specific grade rating information required only of the tire manufacturer or tire brand name owner.

The Petition

The AIAM petitioned the agency to amend 49 CFR 575.6(a), (c), and (d), and the applicable portions of § 575.104(d) to delete the requirement that motor vehicle manufacturers provide UTQGS information to purchasers and prospective purchasers at the point of sale of new vehicles. AIAM argues that new vehicles are sold with tires that are selected by the manufacturers for the particular vehicle models. Thus, the tires are not an item of choice for the vehicle purchaser. AIAM states that UTQGS information can be helpful when consumers are shopping for replacement tires, and that such information would be provided by tire manufacturers or brand name owners as required by the regulation.

AIAM asserts that deletion of the requirement for motor vehicle manufacturers and their dealers to provide UTQGS information for new cars would eliminate unnecessary administrative and paperwork expenses for documents that are of no value to purchasers and prospective purchasers of new motor vehicles. AIAM asserts that in its members' experience, consumers do not ask for this information at new car dealerships.

Finally, AIAM states that some vehicle manufacturers currently include UTQGS information in their owners' manuals where it is available to vehicle owners as a reference when considering the purchase of replacement tires.

Agency Analysis and Proposal

NHTSA has no information on the cost of vehicle manufacturers of supplying UTQGS information at all its sales offices. However, considering that approximately 10 to 12 million vehicles are produced annually equipped with passenger car tires for the U.S. domestic market, the current provisions require many millions of leaflets or brochures, since auto manufacturers are required to provide this information not only to purchasers but to prospective purchasers as well. NHTSA believes that the AIAM point is well taken that purchasers, and especially prospective purchasers of new motor vehicles, would not normally be concerned about replacement tires while shopping for or purchasing a new vehicle.

AIAM makes the point that, although not currently required, some vehicle manufacturers include UTQGS information in their owners' manuals. NHTSA believes that to be an excellent practice and an effective source of UTQGS information since owners' manuals are primary references for vehicle owners regarding virtually all aspects of their vehicles, and remain so for the life of the vehicle. Thus, when vehicle owners are ready to replace their tires, their owner's manual is a convenient source of UTQGS information for their consideration in selecting replacement tires.

NHTSA is persuaded by the AIAM petition that UTQGS information would be of more value to consumers if set forth in owners' manuals rather than in new car show rooms. Accordingly, NHTSA proposes to amend, among other things, § 575.6(a)(1) by requiring

[1] Subpart B of 49 CFR Part 575 includes § 575.103, *Truck-camper loading;* § 575.104, *Uniform tire quality grading standards;* and § 575.105, *Utility vehicles.*

vehicle manufacturers to include § 575.104 information in the owner's manual of each vehicle it produces; and to amend paragraph (d)(1)(iii) of § 575.104 to require that the UTQGS information prescribed in § 575.104, Figure 2, Part II, be included in each vehicle's owner's manual. Those amendments would have the effect of deleting the requirement that vehicle manufacturers provide UTQGS information to purchasers and prospective purchasers of new passenger cars at the point of sale location, and to make that information available to vehicle owners in their owners' manuals. Thus, the information would still be available to consumers, yet would relieve manufacturers of the burden of providing quantities of information of questionable value to purchasers and prospective purchasers of new passenger cars.

NHTSA also proposes to delete the definitions of *brake power unit, lightly loaded vehicle weight, maximum loaded vehicle weight,* and *maximum sustained vehicle speed* from § 575.2(c) because they are no longer pertinent to Part 575. Those definitions applied to §§ 575.101, *Vehicle stopping distance;* 575.102, *Tire reserve load;* and 575.106, *Acceleration and passing ability,* all of which have been removed from Part 575 in previous rulemaking actions. In addition, NHTSA proposes to revise Example 2 in § 575.6(a)(1) to be more representative of the type of tables that might appear in response to § 575.103.

Finally, NHTSA proposes to amend § 575.104(c)(1) to exclude tires with nominal rim diameters of 12 inches or less, rather than tires with nominal rim diameters of 10 to 12 inches. NHTSA is proposing this change in order to eliminate any ambiguity about grading tires smaller than 10 inches, such as tires with rim diameters of 8 inches, that should also be excluded. NHTSA notes that there are few passenger car applications in the U.S. of tires with rim diameters of 12 inches or less.

Issues for NHTSA's Evaluation

As stated above, the objective of the UTOGS is to provide meaningful comparative information to consumers that will assist them in making informed selections when purchasing passenger car tires. NHTSA continues its interest in providing the most effective and efficient ways of promulgating that information. Therefore, in order to obtain additional data for the agency's evaluation of the issues raised in this petition, NHTSA solicits comments on the following specific questions:

1. To what extent do consumers and potential consumers consider the UTOGS information provided by vehicle manufacturers at the point of sale of new passenger cars?

2. What costs are incurred in the preparation, printing, and distribution of UTOGS information at the point of sale of new passenger cars?

3. In what quantities do vehicle manufacturers currently dispense UTOGS information at the point of sale of new passenger cars?

4. How much lead time would be required and what costs would be incurred or saved by vehicle manufacturers by not having to provide UTOGS information at the point of sale, but by having to include such information in owners' manuals?

5. How much time is currently devoted by manufacturers to the preparation and distribution of UTOGS information to purchasers and prospective purchasers of new passenger cars?

6. Should any information be added to or deleted from that UTOGS information currently required?

7. What would be the costs and/or other problems for passenger car manufacturers to provide, in leaflet form or in the owner's manual, the UTOGS ratings for the specific tires provided on each individual vehicle?

Rulemaking Analyses and Notices

(a) *Executive Order 12866 and DOT Regulatory Policies and Procedures.*

This document was not reviewed under Executive order 12866, *Regulatory Planning and Review.* NHTSA has analyzed the impact of this rulemaking action and has determined that it is not ''significant'' under the DOT's regulatory policies and procedures. This proposed action would relieve motor vehicle manufacturers of the requirement to provide UTOGS information to purchasers and prospective purchasers of new motor vehicles at the points of sale of those vehicles, but would require the manufacturers of vehicles equipped with passenger car tires to include that UTOQS information in the owner's manual of each individual such vehicle. Thus, although this proposed action, if finalized, would relieve vehicle manufacturers of one requirement and impose another, NHTSA believes that the cost of adding UTOQS information to owners' manuals, which vehicle manufacturers are already required to provide, would be minimal and in any case, less than the cost of preparing and providing separate UTOQS information at new vehicle dealerships. AIAM pointed out in its petition that some vehicle manufacturers already include UTOQS information in their owners' manuals. NHTSA believes, therefore, that implementation of this proposed regulatory action would result in an as-yet undetermined net overall cost savings to vehicle manufacturers. The agency hopes to receive more specific cost information from the public comments (see question No. 4, Issues for NHTSA's Evaluation, above). The agency believes, however, that any net cost savings would be minimal, therefore not warranting preparation of a full regulatory evaluation.

(b) *Regulatory Flexibility Act.* NHTSA has considered the effects of this rulemaking action under the Regulatory Flexibility Act (5 U.S.C. 601, *et seq.*). I hereby certify that this notice of proposed rulemaking would not have a significant impact on a substantial number of small entities.

The following is the agency's statement providing the factual basis for the certification (5 U.S.C. 605(b)). The amendments proposed herein would primarily affect manufacturers of passenger cars and multipurpose passenger vehicles (MPV) that are equipped with passenger car tires. The Small Business Administration (SBA) regulation at 13 CFR part 121 define a small business in part as a business entity ''which operates primarily within the United States'' (13 CFR 121.105(a)).

SBA's size standards are organized according to Standard Industrial Classification (SIC) codes. SIC code No. 3711, ''Motor Vehicles and Passenger Car Bodies,'' has a small business size standard of 1,000 employees of fewer. SIC code No. 3714, ''Motor Vehicle Parts and Accessories,'' has a small business size standard of 750 or fewer employees.

For manufacturers of passenger cars and MPVs, NHTSA estimates that there are at most 5 small manufacturers of passenger cars in the U.S. Because each such manufacturer serves a niche market, often specializing in replicas or ''classic'' cars, production for each such manufacturer is fewer than 100 cars per year. Thus, there are at most 500 such cars manufactured per year by U.S. small businesses.

By contrast, NHTSA estimates that there are 9 large manufacturers of passenger cars and light trucks and vans (LTV) in the U.S. Total U.S. manufacturing production per year is approximately 15 to 15.5 million passenger cars and LTVs. Thus, NHTSA does not believe that small businesses manufacture even 0.1 percent of the total U.S. passenger car and LTV production per year.

In view of the above discussion, NHTSA believes that small businesses, small organizations, and small governmental units would be affected

by the proposed amendments only to the extent that there could be a very slight, minimal decrease in the cost of new passenger cars. Thus, the agency has not prepared a preliminary regulatory flexibility analysis.

(c) *Executive Order No. 12612, Federalism*. NHTSA has analyzed this rulemaking action in accordance with the principles and criteria of E.O. 12612 and has determined that this rule does not have sufficient federalism implications to warrant the preparation of a Federalism Assessment.

(d) *National Environmental Policy Act*. NHTSA has analyzed this rulemaking action for the purposes of the National Environmental Policy Act and has determined that implementation of this rulemaking action will not have any significant impact on the quality of the human environment.

(e) *Paperwork Reduction Act*. The provisions of the proposed amendments herein requiring manufacturers to provide information in owners' manuals explaining the UTQGS tire quality grades for the benefit of consumers are considered to be third-party information collection requirements as defined by the Office of Management and Budget (OMB) in 5 CFR part 1320. The information collection requirements for 49 CFR part 575 have been submitted to and approved by OMB pursuant to the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* This collection of information authority has been assigned control numbers 2127–0049 for part 575, excluding the UTQGS; and 2127–0519 for § 575.104 (UTQGS).

(f) *Civil Justice Reform*. These proposed amendments would have no retroactive effect. Under 49 U.S.C. 30103(b), whenever a Federal motor vehicle safety standard is in effect, a state or political subdivision of a state may prescribe or continue in effect a standard applicable to the same aspect of performance of a motor vehicle only if the standard is identical to the Federal standard. However, the United States Government, a state or political subdivision of a state may prescribe a standard for a motor vehicle or motor vehicle equipment obtained for its own use that imposes a higher performance requirement than that required by the Federal standard. 49 U.S.C. 30161 sets forth a procedure for judicial review of final rules establishing, amending or revoking Federal motor vehicle safety standards. A petition for reconsideration or other administrative proceedings is not required before parties may file suit in court.

Comments

Interested persons are invited to submit comments on the amendments proposed herein. It is requested but not required that any comments be submitted in duplicate (original and 1 copy).

Comments must not exceed 15 pages in length (49 CFR 553.21). This limitation is intended to encourage commenters to detail their primary arguments in concise fashion. Necessary attachments, however may be appended to those comments without regard to the 15-page limit.

If a commenter wishes to submit certain information under a claim of confidentiality, 3 copies of the complete submission, including the purportedly confidential business information, should be submitted to the Chief Counsel, NHTSA, at the street address noted above and 1 copy from which the purportedly confidential information has been deleted should be submitted to Docket Management. A request for confidentiality should be accompanied by a cover letter setting forth the information in 49 CFR part 512, *Confidential Business Information*.

All comments received on or before the close of business on the comment closing date indicated above for the proposal will be considered, and will be available to the public for examination in the docket at the above address both before and after the closing date. To the extent possible, comments received after the closing date will be considered. Comments received too late for consideration in regard to the final rule will be considered as suggestions for further rulemaking action. Comments on today's proposal will be available for public inspection in the docket. NHTSA will continue to file relevant information in the docket after the closing date, and it is recommended that interested persons continue to monitor the docket for new material.

Those persons desiring to be notified upon receipt of their comments in the rule docket should enclose a self-addressed stamped postcard in the envelope with their comments. Upon receiving the comments the docket supervisor will return the postcard by mail.

List of Subjects in 49 CFR Part 575

Consumer protection, Labeling, Motor vehicle safety, Motor vehicles, Rubber and rubber products, Tires.

In consideration of the foregoing, 49 CFR part 575 would be amended as follows:

PART 575—CONSUMER INFORMATION REGULATIONS

1. The authority citation for part 575 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 575.2(c) would be amended by removing the definitions of *Brake power unit, Lightly loaded vehicle weight, Maximum loaded vehicle weight,* and *Maximum sustained vehicle speed*.

3. Section 575.6 would be amended by revising paragraphs (a)(1), (d)(1)(i), (d)(1)(ii), and (d)(2). Section 575.104 would be amended by revising (c)(1); (d)(1)(ii); and (d)(1)(iii), to read as follows:

§ 575.6 Requirements.

(a)(1) At the time a motor vehicle is delivered to the first purchaser for purposes other than resale, the manufacturer of that vehicle shall provide the Uniform Tire Quality Grading information required by § 575.104(d)(1)(iii) in the owner's manual of each vehicle it produces. The vehicle manufacturer shall also provide to the purchaser, in writing and in the English language, the information specified in § 575.103 of this part that is applicable to that vehicle. The information provided with a vehicle may contain more than one table, but the document must either:

(i) Clearly and unconditionally indicate which of the tables apply to the vehicle with which it is provided, or

(ii) contain a statement on its cover referring the reader to the vehicle certification label for specific information concerning which of the tables apply to that vehicle. If the manufacturer chooses option in paragraph (a)(1)(ii) of this section, the vehicle certification label shall include such specific information.

Example 1. Manufacturer X furnishes a document containing several tables that apply to various groups of vehicles that it produces. The document contains the following notation on its front page: ''The information that applies to this vehicle is contained in Table 5.'' That notation satisfies the requirement.

Example 2. Manufacturer Y furnishes a document containing several tables as in Example 1, with the following notation on its front page:

''Information applies as follows:

Model P. Regular cab, 135 in. (3,430 mm) wheel base—Table 1.
Model P. Club cab, 142 in. (3,607 mm) wheel base—Table 2.
Model Q—Table 3.''

This notation does not satisfy the requirement, since it is conditioned on the

model or the equipment of the vehicle with which the document is furnished, and therefore additional information is required to select the proper table.

* * * * *

(d)(1)(i) Except as provided in paragraph (d)(1)(ii) of this section, in the case of all sections of subpart B other than § 575.104, as they apply to information submitted prior to new model introduction, each manufacturer of motor vehicles shall submit to the Administrator 2 copies of the information specified in subpart B of this part that is applicable to the vehicles offered for sale, at least 90 days before information on such vehicles is first provided for examination by prospective purchasers pursuant to paragraph (c) of this section.

(ii) Where an unforeseen preintroduction modification in vehicle design or equipment results in a change in vehicle performance for a characteristic included in subpart B of this part, a manufacturer of motor vehicles may revise information previously furnished under paragraph (d)(1)(i) of this section by submission to the Administrator of 2 copies of the revised information reflecting the performance changes, at least 30 days before information on such vehicles is first provided to prospective purchasers pursuant to paragraph (c) of this section.

(d)(2) In the case of § 575.104, and all other sections of subpart B as they apply to post-introduction changes in information submitted for the current model year, each manufacturer of motor vehicles, each brand name owner of tires, and each manufacturer of tires for which there is no brand name owner shall submit to the Administrator 3 copies of the information specified in subpart B of this part that is applicable to the vehicles or tires offered for sale, at least 30 days before it is first provided for examination by prospective purchasers pursuant to paragraph (c) of this section.

* * * * *

§ 575.104 Uniform Tire Quality Grading Standards.

* * * * *

(c) *Application*: (1) This section applies to new pneumatic tires for use on passenger cars. However, this section does not apply to deep tread, winter-type snow tires, space-saver or temporary use spare tires, tires with nominal rim diameters of 12 inches or less, or to limited production tires as defined in paragraph (c)(2) of this section.

* * * * *

(d) * * * (1) * * *

(ii) In the case of the information required by § 575.6(c) to be furnished to prospective purchasers of tires, each tire manufacturer or band name owner shall, as part of that information, list all possible grades for traction and temperature resistance, and restate verbatim the explanation for each performance area specified in Figure 2. The information need not be in the same format as in Figure 2. The information must indicate clearly and unambiguously the grade in each performance area for each tire of that manufacturer or brand name owner offered for sale at the particular location.

(iii) Each manufacturer of motor vehicles equipped with passenger car tires shall include in the owner's manual of each such vehicle a list of all possible grades for traction and temperature resistance and restate verbatim the explanation for each performance area specified in Figure 2, Part II. The information need not be in the exact format of Figure 2, Part II, but it must contain a statement referring the reader to the tire sidewall for the specific tire grades for the tires with which the vehicle is equipped, as follows:

Uniform Tire Quality Grading

Quality grades can be found where applicable on the tire sidewall between tread shoulder and maximum section width. For example:

Treadwear 200 Traction AA Temperature A

* * * * *

Issued on May 13, 1998.

L. Robert Shelton,

Associate Administrator for Safety Performance Standards.

[FR Doc. 98–13277 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–59–M

Notices

Federal Register

Vol. 63, No. 98

Thursday, May 21, 1998

This section of the FEDERAL REGISTER contains documents other than rules or proposed rules that are applicable to the public. Notices of hearings and investigations, committee meetings, agency decisions and rulings, delegations of authority, filing of petitions and applications and agency statements of organization and functions are examples of documents appearing in this section.

DEPARTMENT OF AGRICULTURE

Animal and Plant Health Inspection Service

[Docket No. 98–050–1]

Availability of an Environmental Assessment and Finding of No Significant Impact for Field Testing Edwardsiella Ictaluri 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 and finding of no significant impact concerning authorization to ship for the purpose of field testing and the field testing of an unlicensed live bacterial vaccine for use in catfish. A risk analysis, which forms the basis for the environmental assessment, has led us to conclude that field testing this veterinary vaccine will not have a significant impact on the quality of the human environment. Based on our finding of no significant impact, we have determined that an environmental impact statement need not be prepared. With this notice, we state our intention to authorize shipment of this vaccine for field testing 14 days after the date of this notice, unless new substantial issues bearing on the effects of the action contemplated here are brought to our attention. We also state our intention to issue a veterinary biological product license for this vaccine, provided the field test data support the conclusions of the environmental assessment and finding of no significant impact and the product meets all other requirements for licensure.

ADDRESSES: Copies of the environmental assessment and finding of no significant impact may be obtained by contacting the person listed under **FOR FURTHER INFORMATION CONTACT**. Please refer to the docket number, date, and complete title of this notice when requesting copies. Copies of the environmental assessment and finding of no significant impact (as well as the risk analysis with confidential business information removed) are available for public inspection at USDA, room 1141, South Building, 14th Street and Independence Avenue SW., Washington, DC, between 8 a.m. and 4:30 p.m., Monday through Friday, except holidays. Persons wishing to inspect those documents are requested to call ahead on (202) 690-2817 to facilitate entry into the reading room.

FOR FURTHER INFORMATION CONTACT: Dr. Jeanette Greenberg, Technical Writer-Editor, Center for Veterinary Biologics, Licensing and Policy Development, VS, APHIS, USDA, 4700 River Road Unit 148, Riverdale, MD 20737-1231; telephone (301) 734–5338; fax (301) 734–4314; e-mail jgreenberg@aphis.usda.gov.

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 unlicensed 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.

In determining whether to authorize shipment and grant approval for the field testing of the unlicensed 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). APHIS has concluded that field testing the unlicensed veterinary biological product will not significantly affect the quality of the human environment. Based on this finding of no significant impact (FONSI), we have determined that there is no need to prepare an environmental impact statement.

An EA and FONSI have been prepared by APHIS concerning the field testing of the following unlicensed veterinary biological product:

Requester: Alpharma NW Inc.

Product: Edwardsiella Ictaluri Vaccine, Avirulent Live Culture, Code 1531.R0.

Field test locations: Arkansas, Louisiana, and Mississippi.

The above-mentioned product is an *aro*A gene-deleted bacterial vaccine for use as an aid in preventing enteric septicemia in channel catfish.

The EA and FONSI have been prepared in accordance with: (1) The National Environmental Policy Act of 1969, as amended (NEPA) (42 U.S.C. 4321 *et seq.*), (2) regulations of the Council on Environmental Quality for implementing the procedural provisions 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 environmental issues are raised in response to this notice, APHIS intends to authorize shipment of the above product for the initiation of field tests 14 days from the date of this notice.

Because the issues raised by field testing and by issuance of a license are identical, APHIS has concluded that the EA and FONSI that were 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 FONSI, APHIS does not intend to issue a separate EA 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 15th day of May 1998.

Charles P. Schwalbe,

Acting Administrator, Animal and Plant Health Inspection Service.

[FR Doc. 98–13571 Filed 5–20–98; 8:45 am]

BILLING CODE 3410–34–P

DEPARTMENT OF AGRICULTURE

Forest Service

Longleaf Ecosystem Restoration Project, National Forests in Alabama, Conecuh National Forest, Covington and Escambia Counties, AL

AGENCY: Forest Service, USDA.

ACTION: Notice of intent to prepare an Environmental Impact Statement.

SUMMARY: Forest Service will prepare an Environmental Impact Statement on a proposal to emphasize expansion of the longleaf ecosystem across the Conecuh National Forest in a systematic five-year program involving:

1. Restoration cuts (regeneration) of 2,334 acres of off-site trees to restore 64 sites to the native longleaf pine/wiregrass ecosystem.
2. Thinning (intermediate cuts) of 1,939 acres of off-site trees (mostly slash pine) on about 56 sites to promote future conversion to the longleaf pine/wiregrass ecosystem.

DATES: Comments concerning this analysis should be received in writing by June 22, 1998.

ADDRESSES: Send written comments to: District Ranger, Conecuh NF, Route 5, Box 157, Andalusia, Alabama 36420.

FOR FURTHER INFORMATION CONTACT: Gary Taylor, District Ranger, Robert Taylor, Silviculturist, Debbie Foley, NEPA Coordinator, Rick Lint, Wildlife Biologist, Telephone number: 334–222–2555, FAX Number: 334–222–6485.

SUPPLEMENTARY INFORMATION:

A. The Proposal

1. Restoration cut (regenerate) 2,334 acres to restore 64 sites from off-site trees (mostly slash pine) to the native longleaf pine/wiregrass ecosystem. Priority will be given to retaining existing longleaf pines on these sites.
2. Thin (intermediate cut) 1,939 acres of off-site trees (mostly slash pine) of 56 sites to favor and promote future conversion to the native longleaf pine/wiregrass ecosystem.
3. Re-establish restoration cut areas with longleaf pine seedlings within five years of cutting. Site preparation would include drum chopping and burning and/or chemical site prep and burning and/or shearing and windrowing of residual brush and logging slash. The type of site preparation prescribed for each site will be the least intensive treatment needed to insure survival of the planted longleaf seedlings.

B. Needs for the Proposal

1. Restore the longleaf pine/sandhills ecosystem to provide more suitable (preferred) habitat for the red-cockaded woodpecker (RCW) to aid in recovery. RCW is an endangered species.
2. Return acreage occupied by other tree species to native longleaf pine and promote recovery of the longleaf ecosystem.
3. Establish a systematic program to aid in longleaf ecosystem restoration.
4. Implement the goals and objectives of the Forest Plan. Specifically, to protect habitat and improve conditions for threatened, endangered and sensitive species occurring on National Forest lands

C. Nature and Scope of the Decision To Be Made

Whether, and to what extent to, implement an accelerated program of restoring sites to longleaf pine and associated understory species. Historically, these sites were part of the longleaf pine/sandhills ecosystem but now contain off-site species that were artificially introduced.

In the late 1960's and early 1970's regeneration of longleaf pine was difficult and often unsuccessful. Longleaf is more difficult to plant than other southern pines and most research on growing longleaf has only been done in recent years. Currently, about 13,000 acres (about 23%) of native longleaf pine sites on the Conecuh National Forest are forested in slash, loblolly, and in some cases sand pine. Of this, about 10,000 acres were planted to other species (now considered off-site) and about 3,000 acres reverted due to exclusion of fire from an ecosystem that evolved with and, is dependent on, fire. With the exclusion of fire, less tolerant species flourished in the Conecuh National Forest. The longleaf pine/sandhills ecosystem once encompassed some 90+ million acres ranging from Southern Virginia to East Texas. This acreage has been reduced to less than 3 million acres today due to conversion of forests to agriculture and urban areas, as well as conversion to other species.

Beginning in 1987, through applied research, the availability of containerized seedlings, and experience, managers became very successful at planting longleaf pine with the expectation of adequate survival. Seedling survival on the Conecuh National Forest now averages about 90%.

Many sensitive, threatened, and endangered plants and animals depend on this ecosystem for survival of their species. The staff of the Conecuh National Forest is committed to restoring this ecosystem on the native sites best suited to this important forest ecosystem.

D. Proposed Scoping Process

The scoping period associated with this NOI will be thirty (30) days in length, beginning the day after publication of this notice. A public tour will be held on June 5 and 6 from 9 am until 1 pm. These tours are intended to show interested individuals a few of the sites proposed for treatment, as well as similar sites that have been treated in the past few years. These tours will serve as the public scoping meeting.

Scoping for this proposal began in February 1997 when initial information was shared with the public and plans were to document the analysis in an Environmental Analysis. The proposal has been refined since that time and some preliminary issues and alternatives have been developed (and are included in this notice). A decision to proceed with an Environmental Impact Statement has been made due to potential effects for the RCW and the possible need for Formal Consultation with the Fish and Wildlife Service (USDI). Thus, an additional scoping period is being conducted at this time.

The Conecuh National Forest is seeking additional information, comments, and assistance from Federal, State, and local agencies and other individuals or organizations who may be interested in or affected by the proposed action. This input will be used in preparation of the Draft Environmental Impact Statement (DEIS). The scoping process includes:

1. Identifying potential issues.
2. Identifying issues to be analyzed in depth.
3. Eliminating insignificant issues or those which have been covered by a relevant previous environmental analysis.
4. Exploring additional alternatives.
5. Identifying potential environmental effects of the proposed action and alternatives.

A. Preliminary Issues Identified to Date Include

1. What impacts will the release of woody/brushy understory vegetation resulting from thinning treatments have on the efforts to restore historic longleaf ecosystem understory?
2. Can the existing longleaf ecosystem understory species be protected and maintained during implementation of the silviculture treatments (cutting and site preparation)? Currently, many of these stands have a desirable understory and care should be taken to tailor site preparation methods so as to preserve this understory.
3. What short and long-term impacts will there be on the recreational

experience along the Conecuh Trail? Five stands proposed for cutting are visible from the trail and concern exists to protect the scenic value along the trail.

4. Do the long-term benefits of this project to Conecuh National Forest ecosystem restoration efforts justify the costs of reforestation at this time? Short-term economic impacts of the proposed action verses the ecological benefits of the restoration was questioned.

5. Can off-site treatments to restore the longleaf ecosystem be implemented in order to have long-term (and possible short-term) benefits to the red-cocked woodpecker (RCW) while having no negative impacts to the existing RCW population?

6. Long-term ecological concerns/benefits need to take priority over economic incentives. A concern was raised that economic benefits and support of the timber industry should be secondary to long-term ecological needs.

7. Impacts of timber harvest to recreational uses (other than the Conecuh Trail).

8. Importance of downed logs for rare amphibians, especially near known dusky gopher frog breeding ponds.

9. Protection of soil and water resources.

10. Scope/size of the project (whether an EIS might be needed instead of an EA).

11. Fragmentation (concern not to increase).

12. Early successional age class direction in the Land Management Plan (LMP). According to the LMP, early successional habitat should range from a minimum of 6% to a maximum of 17% per habitat unit.

13. Big Bay (Bear Bay) roadless criteria.

14. Cumulative effects. Whether cumulative effects could be adequately evaluated with a project of this magnitude.

B. Possible Alternatives Identified to Date Include

1. No Action: This alternative will serve as a baseline for comparison of alternatives. This alternative will be fully developed and analyzed.

2. Proposed Action: As listed above, this alternative would include a five-year systematic program of thinning and restoration cuts, including site preparation methods proven to result in fully stocked stands of free to grow seedlings in three to five years after cutting is complete.

3. Modified Proposed Action that takes a more conservative approach to longleaf ecosystem restoration with fewer restoration cuts and more thinning. Age class distributions relevant to existing RCW guidance would be given more consideration than long-term ecosystem needs.

4. Follow our normal order of entry into compartments as recommended in the Forest Land Management Plan. This would result in treatment of approximately 78% of the original proposal and reduce the scope of the project.

5. Modified proposed action that is more sensitive to the economic impacts of establishing the new longleaf stands. The majority of the timber to be sold from the regeneration and thinning is pulpwood, thus expected revenues will not cover the cost of site preparation and planting of longleaf in the areas. This alternative will assess ways to reduce the cost of reforestation. This would be accomplished by: (a) Reducing the minimum acceptable stocking per acre; (b) reducing the number of trees planted per acre; (c) reducing acceptable survival rates; and (d) doing the minimum site preparation to accomplish (a). This alternative will also look at other possible funding sources for planting. For example, the National Forest Foundation and American Forests Global Re-Leaf program are two possible non-governmental funding sources that have provided funding in the past. Also, a national initiative for ecosystem restoration funding would fit this project nicely and help in the funding to establish the new stands of longleaf.

6. Treat every known off-site stand (approximately 13,000 acres) by either thinning or restoring to longleaf at this time.

7. Modified Proposed Action that places more emphasis on RCW areas in the Boggy Hollow area and on the western side of the CNF.

8. Modified Proposed Action that would drop all proposed treatments for compartments 34 and 48. This was previously identified on the RARE II inventory (Big Bay).

9. Uneven-age Management. Consider whether the purpose and need could be accomplished with this management regime.

C. Special Permit Needs

There are no special permits required from any State or Federal agencies in order to implement this project.

D. Lead Agency

The USDA Forest Service is the lead agency for this project. The Fish and Wildlife Service (USDI) has been involved with this proposal since inception and will continue to be throughout this analysis. Formal consultation may be required in order to implement one or more of the alternatives.

The Conecuh Ranger District requests that comments be as specific as possible for this proposal and be sent to: District Ranger Gary L. Taylor, USDA, Forest Service, Route 5 Box 157, Andalusia, Alabama 36420.

It is estimated that the draft EIS will be available for public comment by August 15, 1998. It is very important that those interested in this proposed action participate at this time. To be helpful, comments on the DEIS should be as specific as possible and may address the adequacy of the statement or the merits of the alternatives discussed (see the Council on Environmental Quality Regulations for implementing the procedural provisions of the National Environmental Policy Act at 40 CFR 1503.3).

In addition, Federal court decisions have established that reviewers of DEIS's must structure their participation in the environmental review of the proposal so that it is meaningful and alerts the agency to the reviewers' position and contentions: *Vermon Yankee Nuclear Power Corp.* v. *NRDC*, 435 U.S. 519, 553 (1978). Environmental objections that could have been raised at the draft stage may be waived if not raised until after completion of the final environmental impact statement (FEIS). *City of Angoon* v. *Hodel*, 803 F.2d 1016, 1022 (9th Cir. 1986) and *Wisconsin Heritages, Inc.* v. *Harris*, 490 F. Supp. 1334, 1338 (E.D. Wis. 1980). The reason for this is to ensure that substantive comments and objections are made available to the Forest Service at a time when it can meaningfully consider them and respond to them in the FEIS.

Estimated Date for FEIS

After the comment period ends on the DEIS, the comments will be analyzed, considered, and responded to by the Forest Service in preparing the FEIS. The final is scheduled to be completed by November 1998. The responsible official will consider the comments, responses, environmental consequences discussed in the final supplement, applicable laws, regulations, and policies in making a decision regarding this proposal. The responsible official will document the decision and reasons for the decision in the Record of Decision. That decision will be subject to appeal under 36 CFR 215. The responsible official for this project will be Gary L. Taylor, District Ranger for the Conecuh Ranger District, National Forests in Alabama at: Route 5 Box 157, Andalusia, Alabama 36420.

Dated: May 15, 1998.

Gary L. Taylor,

District Ranger.

[FR Doc. 98–13544 Filed 5–20–98; 8:45 am]

BILLING CODE 3410–52–M

DEPARTMENT OF AGRICULTURE

Forest Service

National Urban and Community Forestry Advisory Council

AGENCY: Forest Service, USDA.

ACTION: Notice of meeting.

SUMMARY: The National Urban and Community Forestry Advisory Council will meet in Coeur d'Alene, Idaho, June 4–6, 1998. The purpose of the meeting is to review the status of the Council's annual report, continue discussion on emerging issues in Urban and Community Forestry, and determine the grant categories for the 1999 Challenge Cost-Share grant program.

DATES: The meeting will be held June 4–6, 1998.

ADDRESSES: The meeting will be held at the Shilo Inn, 702 W. Appleway, Coeur d'Alene, Idaho. A tour of local projects will be available June 4, 9:00 a.m.–4:00 p.m.

Individuals who wish to speak at the meeting or to propose agenda items must send their names and proposals to Suzanne M. del Villar, Executive Assistant, National Urban and Community Forestry Advisory Council, 1042 Park West Court, Glenwood Springs, CO 81601.

FOR FURTHER INFORMATION CONTACT: Suzanne M. del Villar, Cooperative Forestry Staff, (970) 928–9264.

SUPPLEMENTARY INFORMATION: The Challenge Cost-Share grant categories, identified by the Council, are advertised annually to solicit proposals for projects to advance the knowledge of, and promote interest in, urban and community forestry. Pursuant to 5 U.S.C. 552b(c)(9)(B), the meeting will be closed from approximately 8:30 to 10:00 a.m. on June 6 in order for the Council to determine the categories for the 1999 Challenge Cost-Share grant program. Otherwise, the meeting is open to the public

Person who wish to bring urban and community forestry matters to the attention of the Council may file written statements with the Council staff before or after the meeting. Public input sessions will be provided and individuals, who have made written requests by May 22, will have the opportunity to address the Council at those sessions. Council discussion is limited to Forest Service staff and Council members.

Dated: May 15, 1998.

Dan Glickman,

Secretary, Department of Agriculture.

[FR Doc. 98–13598 Filed 5–20–98; 8:45 am]

BILLING CODE 3410–11–M

DEPARTMENT OF AGRICULTURE

Natural Resources Conservation Service

Maricopa-Stanfield Watershed, Pinal County, Arizona

AGENCY: Natural Resources Conservation Service, USDA.

ACTION: Notice of availability of finding of no significant impact.

SUMMARY: Pursuant to section 102(2)(c) of the National Environmental Policy Act of 1969; the Council on Environmental Quality Regulations (40 CFR part 1500); and the Natural Resources Conservation Service Regulations (7 CFR part 650); the Natural Resources Conservation Service, U.S. Department of Agriculture, gives notice that an environmental impact statement is not being prepared for the Maricopa-Stanfield Watershed, Pinal County, Arizona.

FOR FURTHER INFORMATION CONTACT: Michael Somerville, State Conservation, Natural Resources Conservation Service, 3003 North Central Avenue, Suite 800, Phoenix, Arizona, 85012. Telephone: (602) 280–8808.

SUPPLEMENTARY INFORMATION: The environmental assessment of this federally assisted action indicated that the project will not cause significant local, regional, or national impacts on the environmental. As a result of these findings, Michael Somerville, State Conservation, has determined that the preparation and review of an environmental impact statement are not needed for this project.

The project purposes are agricultural water management and includes a mixture of land treatment and management practices to conserve irrigation water. The planned works of improvement include irrigation land leveling, suitable irrigation water conveyance, structures for turnouts and water measurement for irrigation water management, and plant, and fertility management practices (not cost-shared) including irrigation water management, crop residue use, conservation cropping sequence, appropriate erosion control practices as needed, nutrient management and pest management.

The Notice of a Finding of No Significant Impact (FONSI) has been forwarded to the Environmental Protection Agency and to various Federal, State, and local agencies and interested parties. A limited number of copies of the FONSI are available to fill single copy requests at the above address. Basic data developed during the environmental assessment are on the file and may be reviewed by contacting Don Paulus, at (602) 280–8780.

No administrative action on implementation of the proposal will be taken until 30 days after the date of this publication in the **Federal Register**.

(This activity is listed in the Catalog of Federal Domestic Assistance under NO. 10.904, Watershed Protection and Flood Prevention, and is subject to the provisions of Executive Order 12372, which requires intergovernmental consultation with State and local officials.)

Dated: May 8, 1998.

Michael Somerville,

State Conservation.

[FR Doc. 98–13597 Filed 5–20–98; 8:45 am]

BILLING CODE 3410–16–M

DEPARTMENT OF AGRICULTURE

Rural-Business Cooperative Service

Notice of Request for Information Collection

AGENCY: Rural Business-Cooperative Service, USDA.

ACTION: Proposed collection; Comments requested.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, this notice announces the Rural Business-Cooperative Service's intention to request a reinstatement of an information collection in support of the program for ''Rural Development Loan Servicing.''

DATES: Comments on this notice must be received by July 20, 1998, to be assured of consideration.

FOR FURTHER INFORMATION CONTACT: David W. Lewis, Loan Specialist, Rural Business-Cooperative Service, USDA, Stop 3224, 1400 Independence Ave., SW, Washington, DC 20250–3224, Telephone: (202) 690–0797.

SUPPLEMENTARY INFORMATION:

Title: Rural Development Loan Servicing.

OMB Number: 0570–0015.

Expiration Date of Approval: April 30, 1998.

Type of Request: Reinstatement of Information Collection.

Abstract: This regulation is for servicing and liquidating loans made by

the Rural Business-Cooperative Service (RBS), under the Intermediary Relending Program (IRP) to eligible IRP intermediaries and applies to ultimate recipients and other involved parties. This regulation is also for servicing the existing Rural Development Loan Fund (RDLF) loans previously approved and administered by the U.S. Department of Health and Human Services (HHS) under 45 CFR part 1076. The objective of the IRP is to improve community facilities and employment opportunities and increase economic activity in rural areas by financing business facilities and community development. This purpose is achieved through loans made by RBS to intermediaries that establish programs for the purpose of providing loans to ultimate recipients for business facilities and community development. The regulations contain various requirements for information from the intermediaries and some requirements may cause the intermediary to require information from ultimate recipients. The information requested is vital to RBS for prudent loan servicing, credit decisions and reasonable program monitoring. The provisions of this subpart supersede conflicting provisions of any other subpart.

Estimate of Burden: Public reporting burden for this collection of information is estimated to average 3.02 hours per response.

Respondents: Non-profit corporations, public agencies, and cooperatives.

Estimated number of Respondents: 420.

Estimated number of responses per respondent: 9.96.

Estimated total annual burden on respondents: 12,675 hours.

Copies of this information collection can be obtained from Cheryl Thompson, Regulations and Paperwork Management Branch, at (202) 692–0043.

Comments

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of RBS, including whether the information will have practical utility; (b) the accuracy of RBS estimate of the burden of the proposed collection of information including the validity of the methodology and assumptions used; (c) ways to enhance the quality, utility and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on 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. Comments may be sent to Cheryl Thompson, Regulations and Paperwork Management Branch, U.S. Department of Agriculture, Rural Development, STOP 0742, 1400 Independence Ave., SW, Washington, DC 20250–0742. All responses to this notice will be summarized and included in the request for OMB approval. All comments will also become a matter of public record.

Dated: May 14, 1998.

Wilbur T. Peer,

Acting Administrator, Rural Business-Cooperative Service.

[FR Doc. 98–13639 Filed 5–20–98; 8:45 am]

BILLING CODE 3410–XY–M

DEPARTMENT OF AGRICULTURE

Rural Business-Cooperative Service

National Sheep Industry Improvement Center; Strategic Plan

AGENCY: Rural Business-Cooperative Service, USDA.

ACTION: Notice of availability.

SUMMARY: The Rural Business-Cooperative Service (RBS) announces the availability of the 1998 Strategic Plan for the National Sheep Industry Improvement Center. Section 759 of the Federal Agriculture Improvement and Reform Act of 1996, known as the 1996 Farm Bill, requires the National Sheep Industry Improvement Center to submit a yearly strategic plan to the Secretary of Agriculture. That plan is now available to the public.

ADDRESSES: Requests for copies of the Plan should be directed to Jay B. Wilson, Executive Director, National Sheep Industry Improvement Center, Denver Federal Center, Building 20, Room A1311, P.O. Box 281028, Lakewood, CO 80228–1028. Phone (303)–236–2858. FAX: (303)–236–7683.

FOR FURTHER INFORMATION CONTACT: Jay B. Wilson at Phone (303)–236–2858 or Dr. Thomas H. Stafford, Director, Cooperative Marketing Division, Cooperative Services, RBS, USDA, 1400 Independence Ave, SW, Stop 3252, Washington, DC 20250–3252, telephone (202) 690–0368, (This is not a toll free number.) FAX 202–690-2723, or e-mail thomas.stafford@usda.gov.

SUPPLEMENTARY INFORMATION: The Federal Agriculture Improvement and Reform Act of 1996, known as the 1996 Farm Bill, established a National Sheep Industry Improvement Center. The Center is to (1) promote strategic development activities and collaborative efforts by private and State entities to maximize the impact of Federal assistance to strengthen and enhance production and marketing of sheep or goat products in the United States; (2) optimize the use of available human capital and resources within the sheep or goat industries; (3) provide assistance to meet the needs of the sheep or goat industry for infrastructure development, business development, production, resource development, and market and environmental research; (4) advance activities that empower and build the capacity of the United States sheep or goat industry to design unique responses to special needs of the sheep or goat industries on both a regional and national basis; and (5) adopt flexible and innovative approaches to solving the long-term needs of the United States sheep or goat industry. The Center has a Revolving Fund established in the Treasury to carry out the purposes of the Center. The Act requires the Center to submit to the Secretary an annual strategic plan for the delivery of financial assistance provided by the Center.

The strategic plan is required to identify (1) goals, methods, and a benchmark for measuring the success of carrying out the plan and how the plan relates to the national and regional goals of the Center; (2) the amount and sources of Federal and non-Federal funds that are available for carrying out the plan; (3) funding priorities; (4) selection criteria for funding; and (5) a method of distributing funding. In addition, the Plan summarizes the sheep and goat industries' needs and problems as determined from a series of public hearings.

The Board of Directors has submitted this plan to the Secretary of Agriculture and wishes to make it available to the public.

Dated: May 13, 1998.

Dayton J. Watkins,

Administrator, Rural Business-Cooperative Service.

[FR Doc. 98–13471 Filed 5–20–98; 8:45 am]

BILLING CODE 3410–XY–U

DEPARTMENT OF COMMERCE

Bureau of the Census

Census Advisory Committees on the African American Population, on the American Indian and Alaska Native Populations, on the Asian and Pacific Islander Populations, and on the Hispanic Population

AGENCY: Bureau of the Census, Commerce.

ACTION: Notice of public meeting.

SUMMARY: Pursuant to the Federal Advisory Committee Act (P.L. 92–463 as amended by P.L. 94–409, P.L. 96–523, and P.L. 97–375), we are giving notice of a joint meeting followed by separate and concurrently held meetings of the Census Advisory Committee (CAC) on the African American Population, the CAC on the American Indian and Alaska Native Populations, the CAC on the Asian and Pacific Islander Populations, and the CAC on the Hispanic Population.

Each of the Committees is composed of nine members appointed by the Secretary of Commerce. They provide an organized and continuing channel of communication between the communities they represent and the Bureau of the Census on its efforts to reduce the differential in the population totals from Census 2000 and on ways that decennial census data can be disseminated to maximize their usefulness to these communities and other users.

The Committees will draw on past experience with the 1990 census process and procedures, results of evaluations and research studies, and the expertise and insight of their members to provide advice and recommendations during the research and development, design, planning, and implementation phases of Census 2000.

DATES: The joint meeting will convene on June 4–5, 1998. The June 4 meeting will begin at 8:30 a.m. and end at 5 p.m; the June 5 meeting will begin at 8:45 a.m. and end at 4:45 p.m.

ADDRESSES: The meeting will take place at the Holiday Inn Hotel & Suites, 625 First Street, Alexandria, Virginia 22314.

FOR FURTHER INFORMATION CONTACT: Anyone wishing additional information about this meeting, or who wishes to submit written statements or questions, may contact Maxine Anderson-Brown, Committee Liaison Officer, Department of Commerce, Bureau of the Census, Room 1649, Federal Building 3, Washington, DC 20233, telephone 301–457–2308, TDD 301–457–2540.

SUPPLEMENTARY INFORMATION: The agenda for the June 4 combined meeting, which will begin at 8:30 a.m. and end at 5 p.m., will include: (1) introductory remarks and update; (2) updates on Dress Rehearsal operations and activities and on Census 2000; (3) observation reports on the Dress Rehearsal; and (4) advertising strategy for the Dress Rehearsal.

The four committees will meet separately and concurrently from 10 a.m. to 12 noon and from 3:30 p.m. to 5 p.m. The Joint Committee meeting will break for the concurrent meetings. The following are the June 4 agendas for the four committees.

The agenda for the CAC on the African American Population will include: (1) the election of the chair-elect; (2) the review of Committee recommendations and responses; (3) an update on constituency-building; (4) the census information centers reengineered; and (5) a review of topics for next day discussions.

The agenda for the CAC on the American Indian and Alaska Native Populations will include: (1) The review of Committee recommendations and responses; (2) the coding of American Indian Tribes; (3) statistical methodology issues; (4) an update on constituency-building; (5) a status report of state-recognized tribes; (6) the census information centers reengineered; (7) an update on census operations relating to American Indian and Alaska Natives areas; and (8) a review of topics for next day discussions.

The agenda for the CAC on the Asian and Pacific Islander Populations will include: (1) The election of chair-elect; (2) the review of Committee recommendations and responses; (3) an update on Hawaiian homelands; (4) a status report on the hiring of partnership specialists; (5) the census information centers reengineered; and (6) a review of topics for next day discussions.

The agenda for the CAC on the Hispanic Population will include: (1) the election of the chair-elect; (2) a review of Committee recommendations and responses; (3) an update on constituency-building; (4) the census information centers reengineered; and (5) a review of topics for next day discussions.

The agenda for the June 5 combined meeting, which will begin at 8:45 a.m. and end at 4:45 p.m., includes: (1) Sampling and estimation in the Dress Rehearsal and in Census 2000; (2) how do we evaluate the Dress Rehearsal and Census 2000?; (3) recruitment and hiring procedures for field operations; (4) topic sessions on reengineered address list operation and on plans for Census 2000 data products; (5) how do we get the communities involved in Census 2000?; (6) an Advisory Committee conversation; (7) Committee recommendations; and, (8) public comment.

On June 5, the four committees will meet separately and concurrently from 11:45 a.m. to 1:45 p.m. The Joint Committee will break for these concurrent meetings. Each of the four Committees (African American Population, American Indian and Alaska Native Populations, Asian and Pacific Islander Populations, and Hispanic Population) will address draft recommendations.

All meetings are open to the public, and a brief period is set aside on June 5 during the closing session for public comment and questions. Individuals with extensive questions or statements must submit them in writing to the Census Bureau Committee Liaison Officer at least three days before the meeting.

These meetings are physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to the Census Bureau Committee Liaison Officer.

Dated: May 18, 1998.

Bradford R. Huther,

Deputy Director, Bureau of the Census.

[FR Doc. 98–13671 Filed 5–20–98; 8:45 am]

BILLING CODE 3510–07–P

DEPARTMENT OF COMMERCE

Economic Development Administration

Notice of Petitions by Producing Firms for Determination of Eligibility To Apply for Trade Adjustment Assistance

AGENCY: Economic Development Administration (EDA), Commerce.

ACTION: To give firms an opportunity to comment.

Petitions have been accepted for filing on the dates indicated from the firms listed below.

LIST OF PETITION ACTION BY TRADE ADJUSTMENT ASSISTANCE FOR PERIOD 04/10/98–5/15/98

Firm name	Address	Date petition accepted	Product
Shepard Clothing Company, Inc.	800 Acushnet Avenue, New Benford, MA 02741.	04/14/98	Mens and boys suits, jackets and blazers.

LIST OF PETITION ACTION BY TRADE ADJUSTMENT ASSISTANCE FOR PERIOD 04/10/98–5/15/98—Continued

Firm name	Address	Date petition accepted	Product
Louisiana Royal Seafood, Inc.	1031 Frank Wyatt, Breaux Bridge, LA 70517.	04/14/98	Processed crab meat and boiled crabs.
F.E. Hale Manufacturing Company	650 West German Street, Herkimer, NY 13350.	04/14/98	Wooden bookcases made of birch, oak and walnut.
A & J Industries, Inc.	213 North Sunnylane, Moore, OK 73153.	04/14/98	Printed circuit boards.
Aggregate Machinery, Inc. dba Thunderbird II	3575 Blossom Drive NE, Salem, OR 97305.	04/16/98	Portable crushers, sorters and screeners, and conveyors.
Contech Manufacturing, Inc.	3400 NE Robson Road, Claremore, OK 74017.	04/21/98	Parts for submersible pumps, chisels, wedges, metal carts, and shovels.
NOA Medical Industries, Inc.	801 Terry Land, Washington, MO 63090.	05/01/98	Hospital/nursing home beds and tables.
ULU Factory, Inc. (The)	298 East Ship Creek Avenue, Anchorage, AK 99501.	05/01/98	Stainless steel alloy knives, silver and gold jewelry, knife handles, sharpeners and wood cutting blocks.
Westin-Nielsen Corporation	4301 White Bear Parkway, St. Paul, MN 55110.	05/01/98	Upholstered chairs with wood frames and swivel chairs with internal wood frame.
Jefferson Mills, Inc.	P.O. Box 698, Pulaski, VA 24301.	05/01/98	Textured nylon and polyester yarn.
G.A. Braun, Inc.	461 E. Brighton Avenue, Syracuse, NY 13205.	05/04/98	Commercial industrial laundry equipment and textile dyeing equipment.
Tech Laboratories, Inc.	955 Belmont Avenue, Haledon, NJ 07508.	05/05/98	Rotary switches, single and three phase transformers, printed circuit boards.
Tridan Tool & Machine, Inc.	130 North Jackson, Danville, IL 61834.	05/05/98	Machinery for bending and forming air conditioning coils and parts for that machinery.
Virginia Plastics Company, Inc.	1701 Midland Road, Salem, VA 24153.	05/06/98	Insulated conducting cable, cable assemblies (cordsets) and printed circuit connectors.
Desert Glass Works, Inc.	2801 North El Paso Street, Colorado Springs, CO 80907.	05/07/98	Machines and parts for semiconductor devices—quartzware tanks, carriers and furnace parts.
Millennium Food Technologies, L.C.	701 North 15th Street, Suite 500, St. Louis, MO 63103.	05/12/98	Confections, condiments, snackfoods and personal care items (body washes, shampoos and oils).
Gastineau Log Homes, Inc.	10423 Old Highway 54, New Bloomfield, MO 65063.	05/12/98	Red oak logs and log home kits.
Hofmann & Leavy, Inc.	3251 Southwest 13th Drive, Deerfield Beach, FL 33442.	05/12/98	Ornamental trimmings—tassles, pompoms and similar articles of cotton or man made fibers.

The petitions were submitted pursuant to Section 251 of the Trade Act of 1974 (19 U.S.C. 2341). Consequently, the United States Department of Commerce has initiated separate investigations to determine whether increased imports into the United States of articles like or directly competitive with those produced by each firm contributed importantly to total or partial separation of the firm's workers, or threat thereof, and to a decrease in sales or production of each petitioning firm.

Any party having a substantial interest in the proceedings may request a public hearing on the matter. A request for a hearing must be received by Trade Adjustment Assistance, Room 7315, Economic Development Administration, U.S. Department of Commerce, Washington, DC 20230, no later than the close of business of the tenth calendar day following the publication of this notice.

The Catalog of Federal Domestic Assistance official program number and title of the program under which these petitions are submitted is 11.313, Trade Adjustment Assistance.

Dated: May 14, 1998.

Anthony J. Meyer,

Coordinator, Trade Adjustment and Technical Assistance.

[FR Doc. 98–13551 Filed 5–20–98; 8:45 am]

BILLING CODE 3510–24–M

DEPARTMENT OF COMMERCE

Bureau of Export Administration

President's Export Council Subcommittee on Export Administration; Notice of Partially Closed Meeting

A partially closed meeting of the President's Export Council Subcommittee on Export Administration (PECSEA) will be held June 17, 1998, 9:00 a.m., at the U.S. Department of Commerce, Herbert C. Hoover Building, Room 4832, 14th Street between Pennsylvania and Constitution Avenues, N.W., Washington, D.C. The Subcommittee provides advice on matters pertinent to those portions of the Export Administration Act, as amended, that deal with United States policies of encouraging trade with all countries with which the United States has diplomatic or trading relations and of controlling trade for national security and foreign policy reasons.

Public Session

1. Opening remarks by the Chairman.
2. Presentation of papers or comments by the public.
3. Update on Administration export control initiatives.
4. Task Force reports.

Closed Session

5. Discussion of matters properly classified under Executive Order 12958, dealing with the U.S. export control program and strategic criteria related thereto.

The General Session of the meeting is open to the public and a limited number of seats will be available. To the extent time permits, members of the public may present oral statements to the Committee. Written statements may be submitted at any time before or after the meeting. However, to facilitate distribution of public presentation materials to the Committee members, the Committee suggests that public presentation materials or comments be forwarded at least one week before the meeting to the address listed below: Ms. Lee Ann Carpenter, OAS/EA MS: 3886C, Bureau of Export Administration, U.S. Department of Commerce, Washington, D.C. 20230.

A Notice of Determination to close meetings, or portions of meetings, of the Subcommittee to the public on the basis of 5 U.S.C. 522(c)(1) was approved October 16, 1997, in accordance with the Federal Advisory Committee Act. A copy of the Notice of Determination is available for public inspection and copying in the Central Reference and Records Inspection Facility, Room 6020, U.S. Department of Commerce, Washington, D.C. For further information, contact Ms. Lee Ann Carpenter on (202) 482–2583.

Dated: May 15, 1998.

William V. Skidmore,

Acting Deputy Assistant Secretary for Export Administration.

[FR Doc. 98–13464 Filed 5–20–98; 8:45 am]

BILLING CODE 3510–33–M

DEPARTMENT OF COMMERCE

National Telecommunication's and Information Administration

Meeting for the Spectrum Planning and Advisory Committee (SPAC)

AGENCY: National Telecommunication's and Information Administration, Commerce.

ACTION: Notice of meeting, Spectrum Planning and Policy Advisory Committee (SPAC).

SUMMARY: In accordance with the provisions of the Federal Advisory Committee Act, 5 U.S.C. Appendix, notice is hereby given that the Spectrum Planning and Policy Advisory Committee (SPAC) will meet on June 12, 1998 from 9:30 a.m. to 5 p.m. in Room 1605 at the United States Department of Commerce, 1401 Constitution Avenue, NW., Washington, DC.

The Committee was established on July 19, 1965 as the Frequency Management Advisory Council (FMAC). The name was changed in April, 1991, and in July, 1993, to reflect the increased scope of its mission. The objective of the Committee is to advise the Secretary of Commerce on radio frequency spectrum planning matters and means by which the effectiveness of Federal Government frequency management may be enhanced. The Committee consists of nineteen members, fifteen from the private sector, and four from the Federal Government, whose knowledge of telecommunications is balanced in the functional areas of manufacturing, analysis and planning, operations, research, academia and international negotiations.

The principal agenda items for the meeting will be:

(1) Discussion of GPS Spectrum Issues for WRC–99;

(2) Present and Future Spectrum Management Actions;

(3) ITU Conferences (D Sector, Plenipot, WRC–99); and

(4) Public Safety Program update.

The meeting will be open to public observations. Public entrance to the building through the main entrance is on 14th Street midway between Pennsylvania Avenue and Constitution Avenue. A period will be set aside for oral comments or questions by the public which do not exceed 10 minutes each per member of the public. More extensive questions or comments should be submitted in writing before June 1, 1998. Other public statements regarding Committee affairs may be submitted at any time before or after the meeting. Approximately 20 seats will be available for the public on a first-come, first-served basis.

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to the Federal Information Relay Service (FIPS) on 1–800–877–8339.

Copies of the minutes will be available upon request 30 days after the meeting.

FOR FURTHER INFORMATION CONTACT: Inquiries may be addressed to the Executive Secretary, SPAC, Mr. Richard A. Lancaster, National Telecommunications and Information Administration, Room 4082, U.S. Department of Commerce, 1401 Constitution Avenue, NW., Washington, DC 20230, telephone 202–482–4487.

Dated: May 14, 1998.

Richard A. Lancaster,

Executive Secretary, Spectrum Planning and Policy Advisory Committee, National Telecommunication's and Information Administration.

[FR Doc. 98–13505 Filed 5–20–98; 8:45 am]

BILLING CODE 3510–60–M

COMMITTEE FOR THE IMPLEMENTATION OF TEXTILE AGREEMENTS

Establishing and Increasing Import Limits for Certain Cotton, Wool and Man-Made Fiber Textile Products Produced or Manufactured in Turkey

May 14, 1998.

AGENCY: Committee for the Implementation of Textile Agreements (CITA).

ACTION: Issuing a directive to the Commissioner of Customs establishing and increasing limits.

EFFECTIVE DATE: May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Roy Unger, International Trade Specialist, Office of Textiles and Apparel, U.S. Department of Commerce, (202) 482–4212. For information in the quota status of these limits, refer to the Quota Status Reports posted on the

bulletin boards of each Customs port or call (202) 927–5850. For information on embargoes and quota re-openings, call (202) 482–3715.

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.

In a Memorandum of Understanding dated April 24, 1998, the Governments of the United States and Turkey agreed, among other things, to establish a limit for cotton and man-made fiber textile products in Categories 352/652 for periods beginning on June 1, 1998 and extending through December 31, 2002. The first period will be prorated, June 1, 1998 through December 31, 1998, followed by four consecutive one-year periods. Also, agreement was reached to increase the 1998 base limits for Categories 338–S/339–S/638–S/639–S and 410. Flexibility adjustments previously applied to Categories 338–S/339–S/638–S/639–S and 410 are being adjusted accordingly.

In the letter published below, the Chairman of CITA directs the Commissioner of Customs to establish a prorated limit for Categories 352/652 for the period June 1, 1998 through December 31, 1998 and to adjust the current limits for Categories 338–S/339–S/638–S/639–S and 410.

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 62 FR 66057, published on December 17, 1997). Also see 62 FR 67839, published on December 30, 1997.

Troy H. Cribb,

Chairman, Committee for the Implementation of Textile Agreements.

Committee for the Implementation of Textile Agreements.

May 14, 1998.

Commissioner of Customs,
Department of the Treasury, Washington, DC 20229.

Dear Commissioner: This directive amends, but does not cancel, the directive issued to you on December 22, 1997, by the Chairman, Committee for the Implementation of Textile Agreements. That directive concerns imports of certain cotton, wool and man-made fiber textile products, produced or manufactured in turkey and exported during the twelve-month period which began on January 1, 1998 and extends through December 31, 1998.

Effective on May 21, 1998, you are directed to establish a limit for Categories 352/652 for the period June 1, 1998 through December 31, 1998 and to increase the current limits for Categories 338–S/339–S/638–S/639–S and 410, pursuant to a Memorandum of Understanding dated April 24, 1998 between the Governments of the United States and Turkey, and as provided for under the Uruguay Round Agreement on Textiles and Clothing (ATC):

Category	New and adjusted limits [1]
338/339/638/639	5,907,500 dozen of which not more than 5,100,324 dozen shall be in Categories 338–S/339–S/638–S/639–S[2].
352/652	1,700,274 dozen.
410/624	1,302,343 square meters of which not more than 959,923 square meters shall be in Category 410.

[1] The limits have not been adjusted to account for any imports exported after December 31, 1997 and May 31, 1998 (Categories 352/652).

[2] Category 338–S: only HTS numbers 6103.22.0050, 6105.10.0010, 6105.100030, 6105.90.8010, 6109.10.0027, 6110.20.1025, 6110.20.2040, 6110.20.2065, 6110.90.9068, 6112.11.0030 and 6114.20.0005; Category 339–S: only HTS numbers 6104.22.0060, 6104.29.2049, 6106.10.001, 6106.10.0030, 6106.90.2510, 6106.90.3010, 6109.10.0070, 6110.20.1030, 6110.20.2045, 6110.20.2075, 611090.9070, 6112.11.0040, 6114.20.0010 and 6117.90.9020; Category 638–S: all HTS numbers except 6109.90.1007, 6109.90.1009, 6109.90.1013 and 6109.90.1025; Category 639–S: all HTS numbers except 6109.90.1050, 6109.90.1060, 6109.90.1065 and 6109.90.1070.

The Committee for the Implementation of Textile Agreements has determined that these actions fall within the foreign affairs exception of the rulemaking provisions of 5 U.S.C. 553(a)(1).

Sincerely,

Troy H. Cribb,

Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc. 98–13466 Filed 5–20–98; 8:45 am]

BILLING CODE 3510–DR–M

COMMITTEE FOR THE IMPLEMENTATION OF TEXTILE AGREEMENTS

Adjustment of Import Limits for Certain Cotton, Man-Made Fiber, Silk Blend and Other Vegetable Fiber Textile Products Produced or Manufactured in the United Arab Emirates

May 14, 1998.

AGENCY: Committee for the Implementation of Textile Agreements (CITA).

ACTION: Issuing a directive to the Commissioner of Customs adjusting limits.

EFFECTIVE DATE: May 21, 1998.

FOR FURTHER INFORMATION CONTACT: Janet Heinzen, 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 or call (202) 927–5850. For information on embargoes and quota re-openings, call (202) 482–3715.

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 current limits for certain categories are being adjusted for swing.

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 62 FR 66057, published on December 17, 1997). Also see 62 FR 63528, published on December 1, 1997.

Troy H. Cribb,

Chairman, Committee for the Implementation of Textile Agreements.

Committee for the Implementation of Textile Agreements

May 14, 1998.

Commissioner of Customs,
Department of the Treasury, Washington, DC 20229.

Dear Commissioner: This directive amends, but does not cancel, the directive issued to you on November 25, 1997, by the Chairman, Committee for the Implementation of Textile Agreements. That directive concerns imports of certain cotton, man-made fiber, silk blend and other vegetable fiber textile products, produced or manufactured in the United Arab Emirates and exported during the twelve-month period which began on January 1, 1998 and extends through December 31, 1998.

Effective on May 21, 1998, you are directed to adjust the limits for the following categories, as provided for under the Uruguay Round Agreement on Textiles and Clothing:

Category	Adjusted twelve-month limit [1]
334/634	276,850 dozen.
336/636	234,553 dozen.
340/640	414,978 dozen.
347/348	497,254 dozen of which not more than 254,295 dozen shall be in Categories 347–T/348–T[2].
352	294,572 dozen.

Category	Adjusted twelve-month limit [1]
847	189,593 dozen.

[1] The limits have not been adjusted to account for any imports exported after December 31, 1997.

[2] Category 347–T: only HTS numbers 6103.19.2015, 6103.19.9020, 6103.22.0030, 6103.42.1020, 6103.42.1040, 6103.49.8010, 6112.11.0050, 6113.00.9038, 6203.19.1020, 6203.19.9020, 6203.22.3020, 6203.42.4005, 6203.42.4010, 6203.42.4015, 6203.42.4025, 6203.42.4035, 6203.42.4045, 6203.49.8020, 6210.40.9033, 6211.20.1520, 6211.20.3810 and 6211.32.0040; Category 348–T: only HTS numbers 6104.12.0030, 6104.19.8030, 6104.22.0040, 6104.29.2034, 6104.62.2006, 6104.62.2011, 6104.62.2026, 6104.62.2028, 6104,69.8022, 6112.11.0060, 6113.00.9042, 6117.90.9060, 6204.12.0030, 6204.19.8030, 6204.22.3040, 6204.29.4034, 6204.62.3000, 6204.62.4005, 6204.62.4010, 6204.62.4020, 6204.62.4030, 6204.62.4040, 6204.62.4050, 6204.69.6010, 6304.69.9010, 6210.50.9060, 6211.20.1550, 6211.20.6810, 6211.42.0030 and 6317.90.9050.

The Committee for the Implementation of Textile Agreements has determined that these actions fall within the foreign affairs exception to the rulemaking provisions of 5 U.S.C. 553(a)(1).

Sincerely,

Troy H. Cribb,

Chairman, Committee for the Implementation of Textile Agreements.

[FR Doc. 98–13467 Filed 5–20–98; 8:45 am]

BILLING CODE 3510–DR–M

CONSUMER PRODUCT SAFETY COMMISSION

Sunshine Act Meeting

TIME AND DATE: Thursday, May 28, 1998, 10:30 a.m.

LOCATION: Room 410, East West Towers, 4330 East West Highway, Bethesda, Maryland.

STATUS: Part Open to the Public; Part Closed.

MATTERS TO BE CONSIDERED:

Open to the Public

1. CPSC Vice Chairman. The Commission will elect a Vice Chairman.

Closed to the Public

2. Compliance Status Report. The staff will brief the Commission on the status of various compliance matters.

For a recorded message containing the latest agenda information, call (301) 504–0709.

CONTACT PERSON FOR ADDITIONAL INFORMATION: Sadye E. Dunn, Office of the Secretary, 4330 East West Highway, Bethesda, MD 20207 (301) 504–0800.

Dated: May 18, 1998.

Sadye E. Dunn,

Secretary.

[FR Doc. 98–13814 Filed 5–19–98; 3:35 pm]

BILLING CODE 6355–01–M

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Availability of Funds for New Foster Grandparent Projects—Nationwide; Correction

AGENCY: Corporation for National and Community Service.

ACTION: Notice; correction.

SUMMARY: The Corporation for National and Community Service published a notice in the **Federal Register** of April 15, 1998, (63 FR 18380) concerning the availability of funds to support Foster Grandparents. The notice contained an incorrect deadline for applications. The new deadline is revised as follows: ''Applications must be received by 5 p.m. Eastern Daylight Time, June 26, 1998''.

FOR FURTHER INFORMATION CONTACT: Barbara Wilson (202) 606–5000, ext. 261.

Dated: May 15, 1998.

Kenneth L. Klothen,

General Counsel, Corporation for National and Community Service.

[FR Doc. 98–13548 Filed 5–20–98; 8:45 am]

BILLING CODE 6050–28–P

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Availability of Funds for New Retired and Senior Volunteer Projects—Nationwide; Correction

AGENCY: Corporation for National and Community Service.

ACTION: Notice; correction.

SUMMARY: The Corporation for National and Community Service published a notice in the **Federal Register** of April 15, 1998, (63 FR 18381) concerning the availability of funds to support RSVP volunteers. The notice contained an incorrect deadline for applications. The new deadline is revised as follows: ''Applications must be received by 5 p.m. Eastern Daylight Time, June 26, 1998''.

FOR FURTHER INFORMATION CONTACT: Barbara Wilson (202) 606–5000, ext. 261.

Dated: May 15, 1998.

Kenneth L. Klothen,

General Counsel, Corporation for National and Community Service.

[FR Doc. 98–13547 Filed 5–20–98; 8:45 am]

BILLING CODE 6050–28–P

CORPORATION FOR NATIONAL AND COMMUNITY SERVICE

Availability of Funds for New Senior Companion Projects—Nationwide; Correction

AGENCY: Corporation for National and Community Service.

ACTION: Notice; correction.

SUMMARY: The Corporation for National and Community Service published a notice in the **Federal Register** of April 15, 1998, (63 FR 18383) concerning the availability of funds to support a national organization and five of its local affiliates to operate new Senior Companion Projects. The notice contained an incorrect deadline for applications. The new deadline is revised as follows: ''Applications must be received by 5 p.m. Eastern Daylight Time, June 26, 1998''.

FOR FURTHER INFORMATION CONTACT: Barbara Wilson (202) 606–5000, ext. 261.

Dated: May 15, 1998.

Kenneth L. Klothen,

General Counsel, Corporation for National and Community Service.

[FR Doc. 98–13546 Filed 5–20–98; 8:45 am]

BILLING CODE 6050–28–P

DEPARTMENT OF DEFENSE

Department of the Navy

Record of Decision and General Conformity Determination for Realignment of F/A–18 Aircraft and Operational Functions From Naval Air Station (NAS) Cecil Field, Florida, to Other East Coast Installations

AGENCY: Department of the Navy, DoD.

ACTION: Notice of record of decision.

SUMMARY: The Department of the Navy, after carefully weighing the operational, environmental, and cost implications of relocating F/A–18 aircraft from NAS Cecil Field to other Naval and Marine Corps installations, announces its decision to realign two F/A–18 fleet squadrons to Marine Corps Air Station (MCAS) Beaufort, South Carolina, and nine F/A–18 fleet squadrons and the Fleet Replacement Squadron (FRS) to Naval Air Station (NAS) Oceana, Virginia.

FOR FURTHER INFORMATION CONTACT: Mr. J. Daniel Cecchini, Atlantic Division Naval Facilities Engineering Command (Code 2032DC), 1510 Gilbert Street, Norfolk, VA 23511–2699, telephone (757) 322–4891.

SUPPLEMENTARY INFORMATION: The text of the entire Record of Decision (ROD) is provided as follows:

The Department of the Navy (DON), pursuant to the Defense Base Closure and Realignment Act of 1990 (10 U.S.C. 2687), Section 102(2)(c) of the National Environmental Policy Act (NEPA) of 1969 (42 U.S.C. 4331 et seq.), and the regulations of the Council on Environmental Quality that implement NEPA procedures (40 CFR Parts 1500–1508), hereby announces its decision to realign two F/A–18 fleet squadrons (24 aircraft and 500 military personnel) to Marine Corps Air Station (MCAS) Beaufort, South Carolina, and nine F/A–18 fleet squadrons and the Fleet Replacement Squadron (FRS) (156 aircraft and 3,700 military and civilian personnel) to Naval Air Station (NAS) Oceana, Virginia. The realignment will be accomplished as set out in Alternative Realignment Scenario (ARS) 2, which is described in the Final Environmental Impact Statement (FEIS).

To support the additional personnel and operation and maintenance of the aircraft, four construction projects are required at MCAS Beaufort; 14 construction projects, primarily consisting of additions to existing facilities, are required at NAS Oceana.

The realignment of the fleet squadrons to MCAS Beaufort will increase aircraft operations at MCAS Beaufort, associated military training areas along the coast of South Carolina and Georgia, and the Townsend Bombing Range in Georgia. The realignment of the fleet squadrons and FRS to NAS Oceana will increase aircraft operations at NAS Oceana, Naval Auxiliary Landing Field (NALF) Fentress, Virginia, and associated military training areas and target ranges located primarily in eastern North Carolina. This includes the Brant Island Shoal (BT–9), Piney Island (BT–11), and Dare County target ranges. Pursuant to Section 176(c) of the Clean Air Act (CAA) (42 U.S.C. 7476(c)), the DON has determined that the realignment of F/A–18 aircraft to NAS Oceana under ARS 2 conforms to Virginia's State Implementation Plan. The entire State of South Carolina is classified as attainment for all criteria pollutants. Therefore, the air quality effects of ARS 2 at MCAS Beaufort are exempt from the General Conformity Rule.

Realignment of the F/A–18 aircraft and operational functions from NAS Cecil Field will begin in 1998 and is expected to be completed in 1999.

Background

The 1993 Defense Base Closure and Realignment Commission (BRAC) recommended closure of NAS Cecil Field and realignment of all of its aircraft and associated personnel to MCAS Cherry Point, North Carolina; MCAS Beaufort, South Carolina; and NAS Oceana, Virginia.

In 1995, the BRAC Commission revised its recommendations regarding realignment of NAS Cecil Field assets by redirecting all aircraft and associated personnel to ''* * * other naval air stations, primarily [NAS] Oceana; [MCAS] Beaufort; [NAS] Jacksonville, Florida; [NAS] Atlanta, Georgia; or other Navy or Marine Corps air stations with necessary capacity and support infrastructure.'' In separate actions, some of the NAS Cecil Field assets have been relocated to NAS Jacksonville (six S–3 ASW squadrons) and NAS Atlanta (two reserve F/A–18 squadrons). This ROD selects a receiving site for the NAS Cecil Field active duty F/A–18 aircraft.

As the 1995 BRAC Commission did not recommend realignment to a specific base, the DON conducted a multi-stage screening process to identify reasonable and feasible alternatives for realignment of NAS Cecil Field F/A–18 active duty aircraft to east/gulf coast Navy or Marine Corps air station(s) with necessary capacity and support infrastructure.

Process

A Notice of Intent (NOI) to prepare an EIS for the transfer of up to ten squadrons of F/A–18 aircraft from NAS Cecil Field to NAS Oceana was published in the **Federal Register** on November 16, 1995. This notice also indicated that separate NEPA documentation would be prepared for the transfer of two operational (active duty) F/A–18 squadrons from NAS Cecil Field to MCAS Beaufort. On August 23, 1996, in recognition of the non-specific language contained in the 1995 BRAC Commission mandates, the DON published an amended NOI in the **Federal Register** indicating its intent to expand its alternatives analysis and to prepare a single comprehensive document for realignment of all operational Atlantic Fleet F/A–18 fleet aircraft and the FRS from NAS Cecil Field. The DON reopened its scoping process and held two additional scoping meetings.

A Notice of Availability (NOA) of the Draft EIS (DEIS) and a Draft CAA Conformity Determination were published in the **Federal Register** on September 19, 1997, and in local newspapers the following week. Seven public hearings were held on the DEIS—one in South Carolina, four in North Carolina, and two in Virginia—between October 20 and November 17, 1997. Approximately 275 individuals, agencies, and organizations submitted comments. All verbal and written comments were addressed in Appendix I of the FEIS.

An NOA of the FEIS and the Final CAA Conformity Determination were published in the **Federal Register** on March 20, 1998, and announced in local newspapers the preceding week. Approximately 440 letters were received on the FEIS during the 30-day public review period; substantive comments are addressed later in this ROD.

Alternatives Considered

The DON screened 20 Navy and Marine Corps air installations located along the Atlantic Coast and the Gulf of Mexico using capacity, support infrastructure, and operational criteria. Only three installations met these criteria—NAS Oceana, MCAS Beaufort, and MCAS Cherry Point.

Because none of the three installations would be able to accommodate all F/A–18 fleet and FRS aircraft without some expansion of existing facilities or new construction, the DON developed alternative realignment scenarios (ARSs) designed to make the best use of excess capacity at each installation.

ARS 1 proposed realigning all 11 F/A–18 fleet squadrons and the FRS at NAS Oceana. This was identified in the FEIS as an operationally preferred alternative because single-siting the Atlantic Fleet F/A–18 Strike/Fighter Wing would provide the same configuration that currently exists at NAS Cecil field. This alternative expands capacity at NAS Oceana and requires 14 construction projects.

ARS 2 proposed realigning two F/A–18 fleet squadrons to MCAS Beaufort and nine F/A–18 fleet squadrons and the FRS to NAS Oceana. This was identified in the FEIS as an operationally acceptable alternative because it would: result in the least degradation of single-site benefits; fully utilize excess capacity at both NAS Oceana and MCAS Beaufort; take advantage of the F/A–18 training facilities that currently exist at MCAS Beaufort; and result in only slightly higher construction and life-cycle costs than ARS 1. It requires some construction at NAS Oceana, but is the lowest cost dual-site alternative.

ARS 3 proposed realigning three F/A–18 fleet squadrons to MCAS Cherry

Point and eight F/A–18 fleet squadrons and the FRS to NAS Oceana. This alternative maximizes the use of existing hangar and apron capacity at MCAS Cherry Point and sends the remaining assets to NAS Oceana. This alternative requires some construction at NAS Oceana.

ARS 4 proposed realigning five F/A–18 fleet squadrons to MCAS Beaufort and six F/A–18 fleet squadrons and the FRS to NAS Oceana. This alternative expands capacity at MCAS Beaufort and requires some construction at NAS Oceana. It utilizes all available capacity at NAS Oceana and reduces noise and air quality impacts at NAS Oceana and NALF Fentress.

ARS 5 proposed realigning five F/A–18 fleet squadrons to MCAS Cherry Point and six F/A–18 fleet squadrons and the FRS to NAS Oceana. This alternative expands capacity at MCAS Cherry Point and requires some construction at NAS Oceana. It utilizes all available capacity at NAS Oceana and reduces noise and air quality impacts at NAS Oceana and NALF Fentress. ARS 5 is the environmentally preferred alternative.

Environmental Impacts

The DON analyzed the potential impacts of all ARSs on: airfield operations; military training areas; target ranges; land use; socioeconomics and community services; infrastructure and utilities; transportation; noise; air quality; topography, geology and soils; water resources; vegetation and wildlife; wetlands; cultural resources; hazardous materials and waste management; and installation restoration programs. The DON also considered the potential cumulative impacts of the project and whether the proposed action would be consistent with federal policies addressing environmental justice.

Since the DON has decided to implement ARS 2, this ROD focuses on the major impacts of ARS 2 at MCAS Beaufort and NAS Oceana. ARS 2 creates significant land use and noise impacts at MCAS Beaufort and NAS Oceana. Impacts on all other resources or functions analyzed in the FEIS were less than significant.

Land Use

Increases in airfield operations at MCAS Beaufort and NAS Oceana will result in the expansion of aircraft noise zones and the expansion and reconfiguration of accident potential zones (APZs). The expansion of APZs and noise zones has the potential to adversely affect use of land underlying the APZs and noise zones. Certain land uses, such as residential development, are considered incompatible with noise zone III where the day-night average noise level (Ldn) is greater than 75dB(A). High-density residential and commercial development is also considered incompatible land use in APZs.

Impacts to future private development actions may occur as a result of implementing ARS 2 because additional area may be subject to development restrictions in local airfield encroachment zones. The City of Beaufort has in place an ordinance that requires disclosure when selling property within the Beaufort noise zones. The City of Virginia Beach's airfield noise attenuation and safety ordinance places additional requirements (i.e., noise attenuation) on private development in high aircraft noise areas within the 1978 Air Installations Compatible Use Zones (AICUZ) noise zones. Although the ARS 2 footprint is larger than the 1978 AICUZ footprint at NAS Oceana, 1 landowners would be able to continue development based on existing property zoning and applicable sound attenuation requirements.

In addition, the U.S. Department of Housing and Urban Development (HUD), the Federal Housing Administration (FHA), and the U.S. Department of Veterans Affairs (VA) restrict the availability of mortgage loans for existing and new homes in noise zones II (i.e. 65–75 dB(A) Ldn) and III (i.e. greater than 75 dB(A) Ldn) and the APZs nearest the runways (i.e. the clear zones).

APZs will expand by 1,894 acres around MCAS Beaufort compared to the 1994 AICUZ. Thirteen percent of this area is residential. APZ expansion at MCAS Beaufort is driven by an increase in the number and type of operations flown by Navy F/A–18 aircraft.

Changes in APZs around NAS Oceana are a result of two different factors. Changes between 1978 APZs and 1997 APZs at NAS Oceana are due in large part to a change in the criteria used by the DON to develop APZs. The result of this change is that APZs will expand by 2,759 and 3,473 acres around NAS Oceana and NALF Fentress, respectively, compared to the 1978 AICUZ. Changes in APZs from 1997 to 1999 reflect the addition of Navy F/A–18 operations as a result of this ROD causing a 1,751 acre APZ increase around NAS Oceana. There would be no change in the size of the APZ around NALF Fentress from addition of the F/A–18 aircraft. Forty-one percent of the total projected NAS Oceana APZ area and five percent of the total projected NALF Fentress APZ areas are residential.

Individuals living or working within an APZ are slightly more at risk from an aircraft accident, in the unlikely event that one occurs, than others living or working near NAS Oceana, NALF Fentress, or MCAS Beaufort outside designated APZs.

Noise

Expansion of noise zones under ARS 2 also has the potential to adversely affect public health and safety. Compared to the 1997 MCAS Beaufort AICUZ, this action will expose 1,659 new people to the 65 to 75 dB(A) Ldn noise zone and 644 new people to the 75+dB(A) Ldn noise zone.

Compared to the 1978 NAS Oceana and NALF Fentress AICUZ, this action will expose 18,486 new people to the 65 to 75 dB(A) Ldn noise zone and 14,668 new people to the 75+dB(A) Ldn noise zone. Compared to the 1997 noise contours and APZs prepared as part of the EIS process, this action will expose 45,852 new people to the 65 to 75 dB(A) Ldn noise zone and 46,781 new people to the 75+dB(A) Ldn noise zone.

Individuals living in 65+dB(A) noise zones may be annoyed and experience interference with daily activities such as sleep, conversation, television viewing, and outdoor recreation. Homeowners may incur costs to ensure that sufficient sound attenuation exists within their dwellings to achieve the Environmental Protection Agency (EPA) desired interior noise level goal of 45 dB(A) Ldn. There is very little probability that long term physical affects, such as hearing loss, will result from exposure to the projected noise levels. A recent study suggests, however, some individuals, particularly children, may temporarily experience stress or elevated blood pressure.

The EIS used public schools as representative sensitive noise receptors to predict impacts. While the discussion of impacts in the FEIS focused on public schools, the impacts discussed in the FEIS could be experienced at private schools and other sensitive receptors as well.

No public schools are located within the 65 dB(A) Ldn or greater noise zone around MCAS Beaufort. Twenty-one public schools in the vicinity of NAS Oceana and NALF Fentress will be within the 65 dB(A) Ldn or greater noise zone with the implementation of ARS 2. Six of these schools are in the 75 dB(A) Ldn or greater noise contour. The projected increases in noise at these schools vary, ranging from an 8 to 20 dB(A) Ldn increase over existing (1997) conditions.

Studies conducted by Cornell University researchers have shown that learning ability and comprehension may be impaired in children exposed to high noise levels. Local school authorities may incur costs to ensure that sufficient sound attenuation exists within the schools to achieve the EPA desired interior noise level goal of 45 dB(A) Ldn. Exposure to high levels of noise while outdoors in schoolyards cannot be mitigated through sound attenuation.

Schools and Housing

Realignment of two squadrons to MCAS Beaufort involves the transfer of 500 military personnel and 600 dependents to the area. Realignment of nine squadrons and the FRS to NAS Oceana involves the transfer of 3,700 military and civilian personnel and 4,600 dependents to the Hampton Roads area. Most of the relocating families will live off-base due to the lack of on-base housing. Sufficient housing vacancies and school capacity exists in the local community to accommodate this influx of personnel. Therefore, local community services and infrastructure are not expected to be significantly impacted at either MCAS Beaufort or NAS Oceana.

Traffic

Traffic will increase in the vicinity of MCAS Beaufort by 1999 due to the proposed realignment and regional growth exclusive of the realignment. Two roadways in the vicinity of MCAS Beaufort are projected to operate at Level of Service (LOS) F in 1999. However, the projected LOS is attributed to regional growth exclusive of the realignment and the island geography of the region. Traffic volume associated with the realignment is less than 2% of the projected 1999 traffic volume for local roadways.

Regional roadways in the vicinity of NAS Oceana will experience an increase in daily traffic as a result of the personnel increase under ARS 2. In most cases, projected LOS on these roadways will be C or better upon completion of roadway improvements already planned by local governments independent of this action. Some roadway segments along First Colonial Road and Virginia Beach Boulevard will continue to operate at LOS D, E, or F, with or without the realignment. The delay in traffic flow associated with LOS D, E, and F is a result of projected regional growth, not traffic increases associated with ARS 2.

Air Quality

Air emissions at NAS Oceana and NALF Fentress will have a net emission increase of approximately 2 tons per year of volatile organic compounds (VOCs), 349 tons per year of nitrogen oxides (NO_X), 298 tons per year of carbon monoxide (CO), 9 tons per year of sulfur dioxide (SO_2) and 195 tons per year of particulate matter (PM_{10}). The DON completed a conformity determination under Section 176(c) of the CAA and EPA's implementing regulations demonstrating that the projected increases in emissions of ozone precursors (VOC and NO_X) conform to the allowable emissions in the recently revised Commonwealth of Virginia's State Implementation Plan (SIP).

In revising its SIP, Virginia expressly included emission levels associated with the realignment of F/A–18 aircraft from NAS Cecil Field. As part of this realignment decision, I approve the Final CAA Conformity Determination included as Appendix E in the FEIS.

Mitigation

Noise

In response to public comment the DON will request congressional authorization to increase the priority of funding to accelerate the construction schedule of an already planned $12 million aircraft acoustical enclosure (''hush house'') at NAS Oceana to reduce noise emissions associated with the high-power, in-aircraft engine maintenance tests.

Land Use

In response to public comment, the DON will also move some local flight pattern operations from runway 5R to runway 5L at NAS Oceana. This mitigation measure will remove the City of Virginia Beach's Brookwood and Plaza Elementary Schools from APZ–2, and decrease the number of people living in the 75 dB Ldn and greater noise zone by 322 individuals.

Response to Comments Received Regarding the Final Environmental Impact Statement

The DON received comments on the FEIS from 1 federal agency, 10 members of Congress and elected state officials, 10 state agencies, 2 local governments, and numerous citizen groups and private individuals. Many of the comments received simply stated support for or opposition to the proposed realignment.

Several commentors suggested that a supplemental EIS was necessary to address additional alternatives. The comments received on the FEIS did not present new or additional information that substantially affected the analysis of environmental impacts in the FEIS. The range of alternatives analyzed in the EIS is based upon the BRAC-directed realignment, provides a logical basis for analysis of environmental impacts and, permits a reasoned choice by the decision-maker. I have reviewed the comments and the range of alternatives and have determined that a supplemental EIS is not warranted.

Other substantive comments received are addressed below by subject matter.

Noise

Sound Attenuation—Many commentors, including EPA, were critical of the lack of discussion of the cost of sound attenuation as mitigation for noise impacts. As indicated in the FEIS, the DON does not have legal authority to expend federal funds on improvements to state, local, or private property. Specific Congressional authorization and appropriation would be required to obtain funds for this purpose. The DON does not intend to request such authority.

In addition, the decision to implement sound attenuation for buildings and homes surrounding the airfields is an individual choice made by local governments, school boards, and individual homeowners. Therefore, any attempt to determine these costs would be speculative in nature.

The FEIS discusses potential sound attenuation such as air conditioning and insulation, and, as requested, the DON will work with local officials to help them conduct detailed engineering evaluations at those schools of particular concern. Upon request, the DON will also provide technical information on sound mitigation to any affected entity in the MCAS Beaufort or NAS Oceana/NALF Fentress regions.

Noise Impacts on Children—Citizens Concerned About Jet Noise noted that the FEIS discussion of impacts on children did not include reference to a study entitled Noise: A Hazard for the Fetus and Newborn (RE9728). In response to that comment, the DON reviewed the study and found it to be not relevant to discussion of noise impacts related to aircraft overflight. The study focused on the type of continuous noise found in the workplace and used a very narrow range of subjects (i.e. those in neonatal intensive care units). The constant workplace noise the study focused on does not correlate to intermittent aircraft noise or the discrete noise events generally associated with an airfield environment. A Cornell University study, Chronic Noise Exposure and Reading Deficits: The Mediating Effects of Language Acquisition (Evans 1997),

which specifically addressed health effects from aircraft noise on children, was used in analyzing impacts associated with aircraft noise in the FEIS.

Property Values

Several commentors criticized the FEIS for not addressing changes in property values due to noise impacts. As discussed in the FEIS, property values are dynamic, vary over time and reflect factors including neighborhood characteristics and individual housing characteristics. Any discussion of changes in property value would, therefore, be too speculative for inclusion in the EIS.

Aircraft Maintenance

Commentors from the State of North Carolina suggested that life cycle costs for facilities at MCAS Cherry Point in ARS 3 and ARS 5 were overstated because they included construction of facilities for, and outfitting of, an F/A–18 Aircraft Intermediate Maintenance Department (AIMD). These commentors suggested that intermediate maintenance work at MCAS Cherry Point in ARS 3 and ARS 5 could be accomplished for a substantially lower cost by using Naval Aviation Depot (NADEP) Cherry Point. In light of these comments, the DON, examined using the NADEP in lieu of a stand-alone AIMD. My evaluation of this issue included a thorough review of Navy AIMD requirements and procedures, a point-by-point analysis of the assertions made regarding NADEP capabilities, and a visit to the NADEP on May 11, 1998. This evaluation confirmed the conclusion that it would be necessary to establish an AIMD at MCAS Cherry Point. The NADEP does not have the excess capacity needed to take on the intermediate maintenance requirement, does not have the capabilities needed to perform AIMD functions, and the additional workload could not be assigned without significant expansion of the facilities, equipment, and workforce at the NADEP. Additionally, the intermediate maintenance workload in support of tactical aircraft needs to be performed by military personnel to ensure maintenance proficiency while deployed and to support sea/shore rotation, technical advancement, and career progression. I also noted that intermediate maintenance on Marine Corps aircraft assigned to Cherry Point is performed by Marine Aircraft Logistical Squadron (MALS), not the NADEP.

Transportation

EPA commented that a peak hour LOS analysis needed to be completed for the roadways around NAS Oceana. NAS Oceana gate count traffic data indicate peak LOS times do not correlate with regional peak traffic flow. Therefore, a peak analysis would not have contributed to the analysis of impacts of the proposed action.

Carbon Monoxide (CO) Hot Spot Analysis

Another commentor suggested that a CO hot spot analysis should have been conducted at heavily used intersections. As discussed in the FEIS, degradation in the LOS would occur on only one on-base roadway segment. No off-base roadway segments would experience degradation of LOS on a long-term basis as a result of the proposed action. Therefore, there is no need to conduct a CO hot spot analysis since the Hampton Roads Planning District Commission traffic study indicated that LOS would not deteriorate due to the planned roadway improvements on roadways that surround the base.

Fuel Handling

EPA asked for more information about potential fuel spills. NAS Oceana has been pro-active in improving its fuel spill prevention, control, and countermeasures in the past few years. Spill response procedures have been and continue to be adequate to handle any spill encountered or expected.

Fuel Dumping

EPA commented on emergency fuel dumping. As noted on pages 4.3–8 and B–1–18 in the FEIS, emergency fuel dumping is extremely rare. DON policy directs that it not occur below 6,000 feet above ground level unless necessary to save the pilot and/or aircraft. In the event of an engine failure on a dual engine fighter, like the F/A–18, the pilot should be able to operate with the remaining engine or climb above 6,000 feet before dumping fuel, thus minimizing the impacts associated with the release of the fuel. (Above 6,000, the fuel has enough time to completely vaporize and dissipate before reaching the ground, and thus has a negligible effect at ground level.) Therefore, any impact from fuel dumping would not be significant.

Sediment and Water Quality Sampling at BT–9/11

EPA recommended gathering more information about sediment quality in target locations. The 1991 Sirrene Study test results for BT–9 which analyzed sediments impacted by approximately 40 years of military bombing activities showed no significant differences in water and sediment quality between the range areas and non-range areas. As a direct result of this study, as indicated in their letter of May 28, 1992, to the Marine Corps, the State of North Carolina determined that continuous monitoring was not required, and future, narrowly focused sampling would only be required as a result of changes in ordnance volume or type, or some indication of significant water or sediment quality degradation.

U.S. Fish and Wildlife Service (USFWS) Red Wolf Re-introduction Program

EPA expressed concern about potential impacts to the Red Wolf. USFWS's only concern has been their continued access to the range to monitor Red Wolf populations. In our response to USFWS comments, set out in Appendix I of the FEIS, the DON agreed to continue to make the range accessible to the USFWS consistent with DON operational use of the range.

Water Supply Issue

One commentor asked for clarification on the water supply sources available to NAS Oceana. In the event of a regional drought, the Navy would rely on an existing Norfolk/Suffolk well pumping contract to assure water for our bases.

Family Housing Costs

The State of North Carolina questioned the family housing costs under ARS 5. Subsequently, the DON conducted a detailed review of all housing costs and other expense items and has identified the following necessary revisions:

1. In ARS 5, the DON inadvertently used the Variable Housing Allowance (VHA) rate for Beaufort, South Carolina, instead of Havelock, North Carolina, to determine family housing costs for five squadrons at MCAS Cherry Point. The change is shown as item 1 in the table below.

2. In all five ARSs, an incorrect number of enlisted bachelor loading was used. The change is shown as item 2 in the table below.

3. In ARS 2, the NAS Oceana off-base bachelor officers housing component was inadvertently omitted. The change is shown as item 3 in the table below.

4. In all five ARSs, Basic Allowance for Quarters (BAQ) was not included since it remains fixed across varying economies. However, since the mix of housing in each ARS varies between on-base and off-base, adding BAQ to the life-cycle cost analysis would improve the accuracy of our analysis. The resulting increase in ARS 1 was

established as the baseline for which adjustments to ARSs 2–5 were made. The change is shown as item 4 on the table below:

	ARS 1 ($M)	ARS 2 ($M)	ARS 3 ($M)	ARS 4 ($M)	ARS 5 ($M)
FEIS	285.3	307.1	465.3	686.4	535.6
Item 1					−9.2
Item 2	−33.7	−33.3	−33.7	−33.7	−33.3
Item 3		5.1			
Item 4		−12.9	−7.8	−75.6	−13.1
Revised	251.6	266.0	423.8	577.1	481.0

The overall effect of these changes is not significant. (Note: Two commentors suggested that the DON use a shorter life-cycle cost analysis than the 30-year analysis performed in the EIS. In response, the DON conducted a 25 year life-cycle analysis for each alternative. The change was not significant.)

Outlying Fields

One commentor suggested that further consideration should be given to the use of outlying fields in addition to or in lieu of NALF Fentress. There are no other outlying airfields within 50 miles of NAS Oceana that could accommodate F/A–18 operations. Chapter 2 of the FEIS discusses the operational and fiscal reasons for establishing a 50-mile limitation.

Seatack Elementary School

One commentor asked for clarification of the location of Seatack Elementary School relative to the new APZs. Under ARS 2, APZ–2 bisects Seatack Elementary school.

Chesapeake Bay Water Quality

EPA expressed concern about potential impacts to the Chesapeake Bay water quality from NO_X emissions. As indicated in the FEIS, the NO_X emissions from the proposed action conform to Virginia's State Implementation Plan. Calculations indicate the net increase in NO_X emissions over the Chesapeake Bay watershed from implementing ARS 2 will be approximately 1 ton per day to the regional airshed. This amount is minor compared to the overall input to the bay from all existing terrestrial and atmospheric sources. Therefore, the affect of the projected increase in air traffic and the associated air emissions over the Chesapeake Bay will be minimal.

State Historic Preservation Determination

Under Section 106 of the National Historic Preservation Act, the Virginia State Historic Preservation Office and the South Carolina Department of Archives and History concurred with the DON's determination that implementation of ARS 2 would have ''no effect'' on historic properties.

Conclusions

In deciding where to realign F/A–18 fleet and FRS aircraft from NAS Cecil Field, I considered the following: 1995 BRAC Commission recommendations concerning capacity and infrastructure; F/A–18 operational requirements; costs associated with construction of facilities, operation and maintenance of aircraft, and training of personnel; environmental impacts; and comments received during the DEIS and FEIS public review periods.

I have analyzed and carefully weighed all of these factors and have decided, on behalf of the DON, to direct realignment of two F/A–18 fleet squadrons (24 aircraft) to MCAS Beaufort, South Carolina, and nine F/A–18 fleet squadrons and the FRS (for a total of 156 aircraft) to NAS Oceana, Virginia. ARS 2, which stations most of the squadrons at NAS Oceana and collocates two Navy squadrons with their Marine Corps counterparts at MCAS Beaufort, offers operational benefits that are not realized under the other alternatives: it establishes air wing integrity at MCAS Beaufort for the joint Navy-Marine Corps squadrons that deploy together, while retaining air wing integrity for the squadrons located at NAS Oceana. It also reduces usage of the North Carolina training ranges, and environmental impacts are slightly less than in ARS 1. While costs are slightly greater than in ARS 1, ARS 2 is the least expensive dual-siting alternative, it fully uses excess capacity at MCAS Beaufort, and it takes full advantage of existing Marine Corps training and maintenance facilities.

Implementation of ARS 2 will result in significant land use and noise impacts on the local communities around MCAS Beaufort, NAS Oceana, and NALF Fentress. In addition to the specific mitigation measures identified in this Record of Decision, the DON will continue to review its operational procedures at NAS Oceana, NALF Fentress, and MCAS Beaufort to determine if any additional mitigation is feasible and practicable.

Dated: May 18, 1998.

Duncan Holaday,

Deputy Assistant Secretary of the Navy (Installations and Facilities).

[FR Doc. 98–13637 Filed 5–20–98; 8:45 am]

BILLING CODE 3810–FF–P

DELAWARE RIVER BASIN COMMISSION

Notice of Commission Meeting and Public Hearing

Visit DRBC's Web Site at http://www.state.nj.us/drbc/drbc.htm

Notice is hereby given that the Delaware River Basin Commission will hold a public hearing on Wednesday, May 27, 1998. The hearing will be part of the Commission's regular business meeting which is open to the public and scheduled to begin at 1:30 p.m. in the Stroud Water Research Center at 970 Spencer Road, Avondale, Pennsylvania.

An informal conference among the Commissioners and staff will be held at 10:00 a.m. at the same location and will include a presentation and discussion on implementation of the Christina Basin strategy; discussion of DRBC advisory committee functions and 1998 DRBC meeting schedule and locations.

In addition to the application listed below which is scheduled for public hearing, the Commission will also address the following: Minutes of the April 21, 1998 business meeting; announcements; General Counsel's report; report on Basin hydrologic conditions; status of compliance—Evansburg Water Company; and public dialogue.

The subject of the hearing will be as follows:

Application for Approval of the Following Project Pursuant to Article 10.3, Article 11 and/or Section 3.8 of the Compact

1. *Camden-Wyoming Sewer and Water Authority D–97–30 CP.* An

application for approval of a ground water withdrawal project to supply up to 21 million gallons (mg)/30 days of water to the applicant's distribution system from existing Well Nos. 2 and 4, and to limit the withdrawal from all wells to 21 mg/30 days. The project is located in Camden-Wyoming, Kent County, Delaware.

Documents relating to this item may be examined at the Commission's offices. A preliminary docket is available upon request. Please contact Thomas L. Brand at (609) 883–9500 ext. 221 concerning docket-related questions. Persons wishing to testify at this hearing are requested to register with the Secretary at (609) 883–9500 ext. 203 prior to the hearing.

Dated: May 12, 1998.

Susan M. Weisman,

Secretary.

[FR Doc. 98–13572 Filed 5–20–98; 8:45 am]

BILLING CODE 6360–01–P

DEPARTMENT OF ENERGY

Notice of Floodplain and Wetlands Involvement of Bayou Choctaw Pipeline Extension to Placid Refinery, Iberville and West Baton Rouge Parishes, Louisiana

AGENCY: Department of Energy.

ACTION: Notice.

SUMMARY: The Department of Energy (DOE) hereby provides notice that the proposed construction of an approximately 16-mile crude oil pipeline segment to connect the existing DOE-owned Bayou Choctaw pipeline in Iberville Parish, Louisiana, to the Placid Oil Refinery in Port Allen, West Baton Rouge Parish, Louisiana, would occur in a 100-year floodplain and would involve wetlands. Pursuant to 10 CFR Part 1022, DOE will prepare a floodplain and wetlands assessment which will be incorporated in an environmental assessment (EA) being prepared in accordance with the National Environmental Policy Act (NEPA).

DATES: Written comments should be postmarked or transmitted electronically or by facsimile by June 5, 1998.

ADDRESSES: Written comments, questions about the proposed action, and requests to review the draft EA should be directed to Mr. Hal Delaplane, Strategic Petroleum Reserve (FE–42), U.S. Department of Energy, 1000 Independence Avenue, SW, Washington, DC 20585, Telephone (202) 586–4730, Fax (202) 586–7919, E-mail = hal.delaplane@hq.doe.gov.

FOR FURTHER INFORMATION ON GENERAL DOE FLOODPLAIN AND WETLANDS ENVIRONMENTAL REVIEW REQUIREMENTS, CONTACT: Carol M. Borgstrom, Director, Office of NEPA Policy and Assistance (EH–42), U.S. Department of Energy, 1000 Independence Avenue, SW, Washington, DC 20585, Telephone (202) 586–4600 or (800) 472–2756.

SUPPLEMENTARY INFORMATION: Under Executive Order 11988, Floodplain Management, and 10 CFR Part 1022, Compliance with Floodplain-Wetlands Environmental Review Requirements (http://tis-nt.eh.doe.gov/nepa/tools/regulate/nepa__reg/1022/1022.htm), notice is given that DOE is considering a request from Shell Pipe Line Corporation (Shell) to amend Shell's lease of DOE's Bayou Choctaw crude oil pipeline. Shell has asked for the change to enable it to construct its own 16-mile pipeline from a tie-in to the DOE pipeline at the Strategic Petroleum Reserve Bayou Choctaw Facility in Iberville Parish, Louisiana, to the Placid Oil Refinery near Port Allen, West Baton Rouge Parish, Louisiana. This project would not occur within the Coastal Zone of Louisiana but would be within a 100-year floodplain and would involve wetlands.

Before it approves Shell's request, DOE will prepare an EA of the construction and operation of the extended Bayou Choctaw pipeline to Placid Refinery pursuant to 10 CFR Part 1021, DOE NEPA Implementing Procedures (http://tis-nt.eh.doe.gov/nepa/tools/regulate/nepa__reg /1021 /nepa1021.htm). Shell has also applied to the U.S. Army Corps of Engineers (USACE), New Orleans District, for a construction permit pursuant to Section 404 of the Clean Water Act. DOE is coordinating its NEPA compliance process with the USACE permit process (33 CFR Parts 320–330, http://ceres.ca.gov/wetlands/permitting/404/corps__permit__regulations.html).

The 24-inch steel pipeline would be constructed in existing pipeline and utility corridors for all but about 2 miles of its length. As shown in the map below, about 7.7 miles of the proposed route is within the 100-year floodplain. The pipeline would cross sugarcane fields and about 8.5 miles of forested wetlands. About 86 acres of bottomland hardwoods would be impacted.

Push-site construction would be used in wetland areas. The pipeline would be directionally drilled under the Intracoastal Waterway and Interstate 10. Eight additional road crossings and two railroad crossings would be by slick bore or directional drill. Crossings of Bayou Bourbeaux and six drainage canals would be by open cut trench or directional drill.

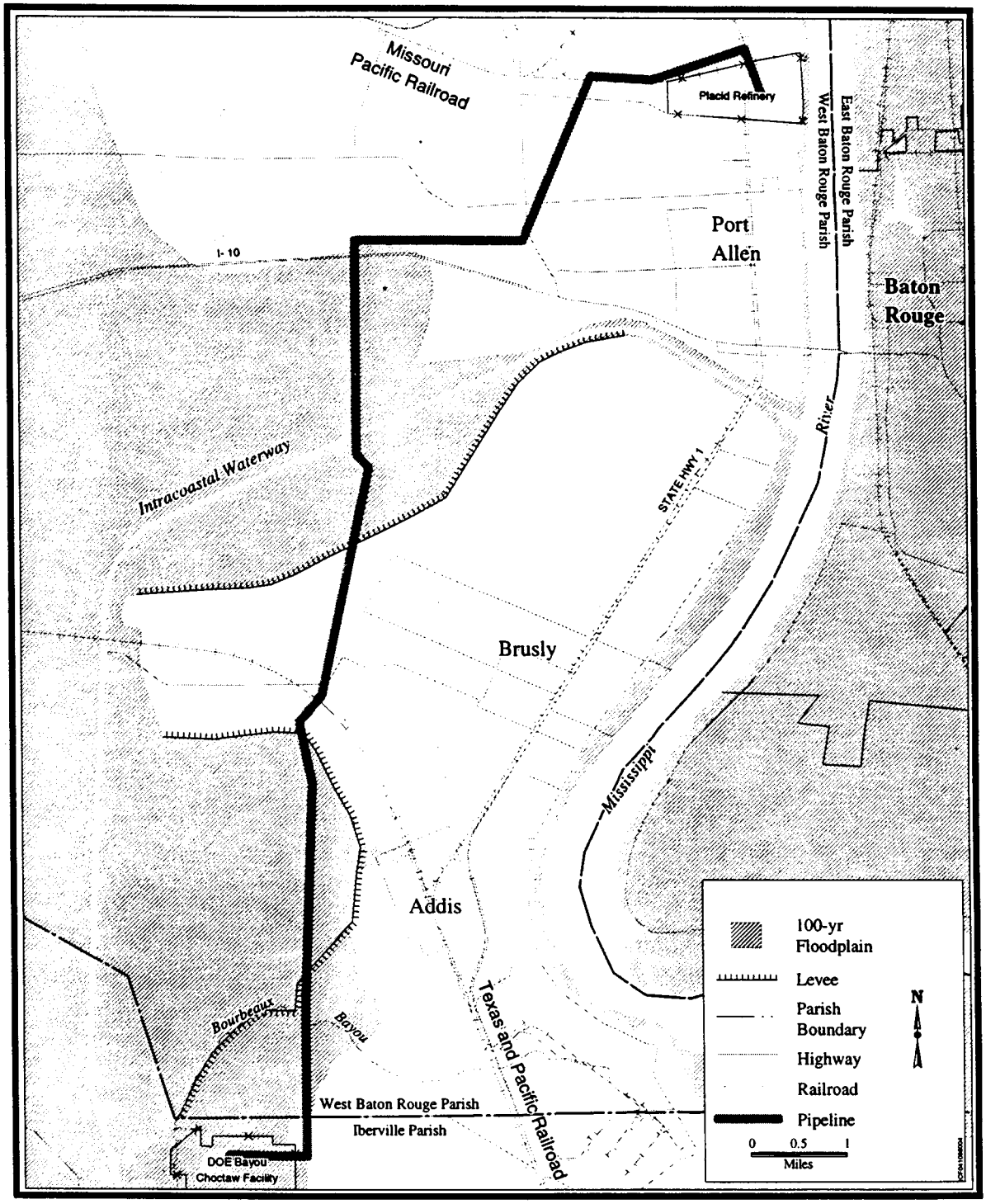
In accordance with DOE regulations for compliance with floodplain and wetlands environmental review requirements (10 CFR Part 1022), DOE will prepare a floodplain and wetlands assessment for this proposed action. The assessment will be incorporated in the EA being prepared for the proposed project in accordance with NEPA. DOE expects to have a draft of the EA available for public review in June 1998. Copies may be requested by telephone, facsimile, or e-mail from the address given above. A floodplain statement of findings will be included in any finding of no significant impact that is issued following completion of the EA or may be issued separately.

Issued in Washington, DC, on May 1, 1998.

Robert S. Keipowing,

Acting, Assistant Secretary for Fossil Energy.

BILLING CODE 6450–01–P



Floodplains Near Proposed Pipeline

[FR Doc. 98–13589 Filed 5–20–98; 8:45 am]

BILLING CODE 6450–01–C

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. TM98–8–23–000]

Eastern Shore Natural Gas Company; Notice of Proposed Changes in FERC Gas Tariff

May 15, 1998.

Take notice that on May 12, 1998, Eastern Shore Natural Gas Company (ESNG) tendered for filing certain revised tariff sheets in the above captioned docket as part of its FERC Gas Tariff, First Revised Volume No. 1, bear a proposed effective date of June 1, 1998.

ESNG states that the purpose of this instant filing is to track rate changes attributable to storage service purchased from Columbia Gas Transmission Corporation (Columbia). The storage service purchased from Columbia is under its Rate Schedules SST and FSS the costs of which comprise the rates and charges under ESNG's Rate Schedule CFSS. The changes are reflected in the rates applicable to storage service rendered by ESNG under its Rate Schedule CFSS.

ESNG states that copies of the filing have been served upon its jurisdictional customers and interested State Commissions.

Any person desiring to be heard or to protest this filing should file a motion to intervene or a protest with the Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, in accordance with Sections 385.214 and 385.211 of the Commission's Rules and Regulations. All such motions or protests must be filed as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13491 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP85–221–105]]

Frontier Gas Storage Company; Notice of Sale Pursuant to Settlement Agreement

May 15, 1998.

Take notice that on May 12, 1998, Frontier Gas Storage Company (Frontier), c/o Reid & Priest, Market Square, 701 Pennsylvania Ave., N.W., Suite 800, Washington, D.C. 20004, in compliance with provisions of the Commission's February 13, 1985, Order in Docket No. CP82–487–000, *et al.*, submitted an executed Service Agreement under Rate Schedule LVS–1 providing for the possible sale of up to a daily quantity of 30,000 MMBtu, not to exceed 5 Bcf of Frontier's gas storage inventory on an ''as metered'' basis to Prairielands Energy Marketing, Inc., for term ending May 31, 1999.

Under Subpart (b) of Ordering Paragraph (F) of the Commission's February 13, 1985, Order, Frontier is ''authorized to commence the sale of its inventory under such an executed service agreement fourteen days after filing the agreement with the Commission, and may continue making such sale unless the Commission issues an order either requiring Frontier to stop selling and setting the matter for hearing or permitting the sale to continue and establishing other procedures for resolving the matter.''

Any person desiring to be heard or to make a protest with reference to said filing should, within 10 days of the publication in such notice in the **Federal Register**, file with the Federal Energy Regulatory Commission (888 1st Street, N.E., Washington, D.C. 20426) a motion to intervene or protest in accordance with the requirements of the Commission's Rules of Practice and Procedures, 18 CFR 385.214 or 385.211. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Copies of this filing are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13492 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Secretary of Energy Advisory Board; Notice of Open Meeting

AGENCY: Department of Energy

SUMMARY: Consistent with the provisions of the Federal Advisory Committee Act (Public Law 92–463, 86 Stat. 770), notice is hereby given of the following advisory committee meeting:

Name: Secretary of Energy Advisory Board—Task Force on Education

DATES AND TIMES: Friday, June 5, 1998, 8:30 AM—3:30 PM.

ADDRESSES: U.S. Department of Energy, Program Review Center (Room 8E–089), Forrestal Building, 1000 Independence Avenue, SW, Washington, D.C. 20585

FOR FURTHER INFORMATION CONTACT: Bruce Bornfleth, Secretary of Energy Advisory Board (AB–1), U.S. Department of Energy, 1000 Independence Avenue, SW, Washington, D.C. 20585, (202) 586–4040 or (202) 586–6279 (fax).

SUPPLEMENTARY INFORMATION: The purpose of the Task Force on Education is to provide information and recommendations to the Secretary of Energy Advisory Board on ways to make the Department's scientific, technical and supercomputing capabilities more available to our Nation's schools, colleges and universities, and to provide recommendations on how the Department can best enhance science, technology, engineering and mathematics education in the United States. The Task Force on Education will prepare a report for submission to the Secretary of Energy Advisory Board.

Tentative Agenda

Friday, June 5, 1998

8:30–8:45 AM Welcome and Opening Remarks—Dr. Hanna Gray, Task Force Chairman.
8:45–10:15 AM Task Force Discussion.
10:15–10:30 AM Break.
10:30–12:00 PM Presentations.
12:00–1:00 PM Lunch Break.
1:00–2:30 PM Presentations.
2:30–3:15 PM Discussion of Task Force Action Plan.
3:15–3:30 PM Public Comment Period.

This tentative agenda is subject to change. The final agenda will be available at the meeting.

Public Participation: The Chairman of the Task Force is empowered to conduct the meeting in a fashion that will, in the Chairman's judgment, facilitate the orderly conduct of business. During its meeting in Washington, D.C., the Task Force welcomes public comment. Members of the public will be heard in the order in which they sign up at the

beginning of the meeting. The Task Force will make every effort to hear the views of all interested parties. Written comments may be submitted to Skila Harris, Executive Director, Secretary of Energy Advisory Board, AB–1, U.S. Department of Energy, 1000 Independence Avenue, SW, Washington, D.C. 20585.

Minutes: Minutes and a transcript of the meeting will be available for public review and copying approximately 30 days following the meeting at the Freedom of Information Public Reading Room, 1E–190 Forrestal Building, 1000 Independence Avenue, SW, Washington, D.C., between 9:00 AM and 4:00 PM, Monday through Friday except Federal holidays. Information on the Task Force on Education and future reports may be found at the Secretary of Energy Advisory Board's web site, located at http://www.hr.doe.gov/seab.

Issued at Washington, D.C., on May 15, 1998.

Rachel M. Samuel,

Deputy Advisory Committee Management Officer.

[FR Doc. 98–13588 Filed 5–20–98; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Small Entity Compliance Guidance and Civil Penalty Reduction and Waiver Pursuant to the Small Business Regulatory Enforcement Fairness Act of 1996; Statement of Policy

AGENCY: Department of Energy.

ACTION: Notice.

SUMMARY: The Department of Energy today publishes a statement of policy regarding guidance to small entities concerning compliance with statutory and regulatory requirements and the waiver or reduction of civil penalties for small entities that violate statutory and regulatory requirements. This policy statement is published to comply with sections 213 and section 223 of the Small Business Regulatory Enforcement Fairness Act of 1996.

DATES: This policy takes effect on June 22, 1998.

ADDRESSES: Interested persons may submit any comments or suggestions with respect to this policy statement to Michael W. Bowers, U.S. Department of Energy, Office of General Counsel, GC–74, 1000 Independence Avenue, SW, Washington, DC 20585, (202) 586–9507.

FOR FURTHER INFORMATION CONTACT: Michael W. Bowers, U.S. Department of Energy, Office of General Counsel, GC–74, 1000 Independence Avenue, SW, Washington, DC 20585, (202) 586–9507.

SUPPLEMENTARY INFORMATION:

I. Background

The Small Business Regulatory Enforcement Fairness Act (SBREFA), which was enacted as title II of Pub. L. 104–121, was signed into law on March 29, 1996. The primary goals of SBREFA as stated in the Act are to implement recommendations of the 1995 White House Conference on Small Business; provide small entities enhanced opportunities for judicial review of final agency action; encourage small business participation in the regulatory process; develop more accessible sources of information on regulatory and reporting requirements for small entities; create a more cooperative regulatory environment for small businesses; and make federal regulators more accountable for ''excessive'' enforcement actions.

Section 221 of SBREFA, 5 U.S.C. 601 note, defines the term ''small entity'' as having the same meaning as in section 601 of the Regulatory Flexibility Act (RFA). The RFA defines ''small entity'' as any ''small business,'' ''small organization,'' or ''small governmental jurisdiction.'' 5 U.S.C. 601(6). Under the RFA, a ''small business'' has the same meaning as ''small business concern'' under section 3 of the Small Business Act, unless an agency, after consultation with the Office of Advocacy of the Small Business Administration (SBA) and after an opportunity for public comment, establishes other appropriate definitions. 5 U.S.C. 601(3). Under the Small Business Act, a ''small business concern'' is one that is independently owned and operated and not dominant in its field of operation (15 U.S.C. 632(a)(1)). SBA regulations further define ''small business concern'' using number of employees or annual income by industry category. 13 CFR part 121. SBA's regulations also provide that the affiliates of an enterprise are included in determining its size. 13 CFR 121.103. The RFA defines ''small organization'' as a not-for-profit enterprise which is independently owned and operated and not dominant in its field, unless an agency, after opportunity for public comment, establishes other definitions of the term appropriate to its activities and publishes such definitions in the **Federal Register**. 5 U.S.C. 601(4). The RFA defines a ''small governmental jurisdiction'' as governments of cities, counties, towns, townships, villages, school districts, or special districts with a population of less than 50,000, unless an agency establishes other appropriate definitions after opportunity for public comment. 5 U.S.C. 601(5). The Department of Energy (DOE or Department) has not established alternative definitions of these terms. The RFA definitions of these terms are included in Section III of the policy statement published today.

The Department currently does not administer any program that is focused principally on the regulation of small entities. DOE does administer programs that involve financial assistance to, or procurement from, small entities. Moreover, requirements in particular rules issued by DOE, which may be enforced by assessment of civil penalties, may apply to some small entities as well as large ones. Therefore, to comply with sections 213 and 223 of SBREFA, the Department has issued the policies set forth in this notice in order to provide for: (1) Guidance to small entities concerning compliance with statutes and regulations under the Department's jurisdiction, and (2) the reduction and waiver of civil penalties for small entities.

II. Policy on Compliance Guidance to Small Entities

Under section 213 of SBREFA, 5 U.S.C. 601 note, each agency that regulates the activities of small entities is directed to establish a program for responding to inquiries from small entities concerning compliance, utilizing existing functions and personnel of the agency to the extent practicable. Section 213(a) provides: ''Whenever appropriate in the interest of administering statutes and regulations within the jurisdiction of an agency which regulates small entities, it shall be the practice of the agency to answer inquiries by small entities concerning information on, and advice about, compliance with such statutes and regulations, interpreting and applying the law to specific sets of facts supplied by the small entity. In any civil or administrative action against a small entity, guidance given by an agency applying the law to facts provided by the small entity may be considered as evidence of the reasonableness or appropriateness of any proposed fines, penalties or damages sought against such small entity.''

The Department provides a variety of information and guidance to persons about compliance with the requirements of the programs it administers. Each substantive area under the Department's jurisdiction has staff members who respond to inquiries about compliance with applicable laws and regulations. If sources of general information are insufficient to provide the needed guidance or assistance, DOE staff members may provide specific, informal advice, or may advise the requester to

use a more formal method to obtain answers to its inquiry. Following are some examples of information and procedures that are available to persons, including small entities, subject to particular DOE regulatory requirements:

• DOE directives, including compliance guides, are available on an Internet website (http://www.explorer.doe.gov). These directives primarily apply to the Department's management and operation of its facilities and to DOE contractors and subcontractors if incorporated into contracts. Explorer links to the DOE Technical Standards Program's home page (http://apollo.osti.gov/html/techstds/techstds.html), which provides access to guides and handbooks pertaining to use of technical standards in DOE programs. The Department of Energy home page (http://www.doe.gov) also includes links to information (e.g., names and telephone numbers of contact persons) provided by various program offices to assist persons who must comply with regulatory requirements.

• DOE has issued a formal policy that addresses issuance of guidance documents, including technical standards, to assist contractors in implementing environment, safety and health requirements at DOE sites (DOE P 450.2A). That policy also commits DOE to provide opportunities for public input on guidance relating to nuclear safety rules, including publication of notice of the availability of such guidance and acceptance of public comments. DOE also has published a detailed statement of policy concerning enforcement of nuclear safety requirements as an appendix to its procedural rules for DOE nuclear activities. 10 CFR part 820, appendix A. This policy statement was amended on October 8, 1997 (62 FR 52479).

• The Office of Energy Efficiency and Renewable Energy has promulgated rules for the Alternative Fuel Transportation Program that allow an owner or operator of a fleet of motor vehicles to request an interpretive ruling on how DOE's regulations apply to its particular facts and circumstances. 10 CFR 490.5. The regulations provide that ''[n]o person who obtains an interpretive ruling * * * shall be subject to an enforcement action for civil penalties or criminal fines for actions reasonably taken in reliance thereon * * *'' 10 CFR 490.5(i). The Office also issued a ''plain English'' compliance guide when it published regulations for the program.

The Department has not established a separate program specifically to provide compliance guidance to small entities. The programs administered by DOE generally involve large companies with contracts to conduct operations at DOE facilities or regulation of private sector companies, such as appliance manufacturers, that are not small entities. The Department's policy is that each program office with authority to bring enforcement actions against small entities for violations of statutory or regulatory requirements should provide compliance guidance to small entities to the extent appropriate and practicable. Under this policy, DOE usually will answer inquiries of small entities concerning compliance if doing so does not interfere with a matter that currently is under investigation or the subject of governmental proceedings.

The Department's policy on providing compliance guidance to small entities includes several conditions on responding to requests by small entities for written guidance applying law to facts they have provided. These conditions are necessary because SBREFA provides that agency guidance may be considered as evidence in any civil or administrative enforcement proceeding. The policy provides that before responding in writing to a small entity's request, DOE offices should require the person who has requested the written guidance to provide in writing the specific facts and circumstances relevant to its request and to identify the pertinent statute or regulation. In addition, the policy calls for DOE offices to consult with legal counsel, and any other DOE office or agency with an interest in the matter, before providing a written response to a small entity. With regard to DOE nuclear activities, the Secretary has delegated to the General Counsel the responsibility for formulating and issuing any interpretation concerning the Atomic Energy Act of 1954, other nuclear statute, or a DOE nuclear safety requirement. 10 CFR 820.51.

III. Policy on Reduction and Waiver of Civil Penalties for Small Entities

Section 223(a) of SBREFA, 5 U.S.C. 601 note, provides the following general standard for agency reduction and waiver policies: ''Each agency regulating the activities of small entities shall establish a policy or program * * * to provide for the reduction, and under appropriate circumstances for the waiver, of civil penalties for violations of a statutory or regulatory requirement by a small entity. Under appropriate circumstances, an agency may consider ability to pay in determining penalty assessments on small entities.''

DOE interprets the term ''civil penalites'' in section 223 to mean civil money penalties. This interpretation is consistent with the provision that an agency may consider a small entity's ''ability to pay,'' and the requirement in section 223(c) that each agency report to Congress on the ''total amount of penalty reductions and waivers'' under its policy or program.

Section 223(b) provides that agency policies or programs are ''(s)ubject to the requirements of other statutes'' and, thus, do not supersede existing laws on penalties. It provides, moreover, that agency policies or programs shall contain conditions or exclusions, which may include, but shall not be limited to: (1) Requiring the small entity to correct the violation within a reasonable time; (2) limiting the applicability to violations discovered through participation by the small entity in a compliance assistance or audit program operated or supported by the agency or a state; (3) excluding from the program small entities that have been subject to multiple enforcement actions by the agency; (4) excluding violations involving willful or criminal conduct; (5) excluding violations that pose serious health, safety, or environmental threats; and (6) requiring a good faith effort to comply with the law.

Several conditions or exclusions suggested in SBREFA are similar to provisions of a Presidential memorandum on regulatory reform issued on April 21, 1995, which directed executive agencies to modify penalties for small businesses. The memorandum provides that agencies shall exercise their discretion ''to waive the imposition of all or a portion of a penalty when the violation is corrected within a time period appropriate to the violation in question * * *. The provisions (of this section) shall apply only where there has been a good faith effort to comply with applicable regulations and the violation does not involve criminal wrongdoing or significant threat to health, safety, or the environment.'' Memorandum of the President of the United States to Executive Agencies, ''Regulatory Reform—Waiver of Penalties and Reduction of Reports'' (April 21, 1995) (5 U.S.C. 601 note).

The Department has authority to impose civil penalties under various statutes. Section 18 of the Price-Anderson Amendments Act of 1988, 42 U.S.C. 2282a, authorizes DOE to impose civil money penalties of up to $110,000 on certain persons for violation of DOE nuclear safety requirements in any

applicable rule, regulation or order.[1] The Department has published a statement of enforcement policy for implementing this authority. 10 CFR part 820, appendix A. Under the National Defense Authorization Act for Fiscal Years 1992 and 1993, DOE may impose civil penalties on any contractor of DOE who fails to provide for the training of individuals involved in hazardous substance response or emergency response at DOE nuclear weapons facilities, or who fails to certifiy such training. 42 U.S.C. 7274d. The Department also has authority to impose civil penalties for violation of certain provisions of the Energy Policy Act, 42 U.S.C. 13262; the Energy Policy and Conservation Act, 42 U.S.C. 6303; the Program Fraud Civil Remedies Act, 31 U.S.C. 3801–3812; and various other statutes. As mentioned previously, the programs administered by DOE generally involve large contractors and companies, but DOE rules sometimes apply to individual small entities that may be subject to assessment of civil penalties for violation of regulatory requirements.

DOE will consider whether to reduce or waive civil penalties that have been assessed against small entities on a case-by-case basis. Under the DOE policy, small entities are not eligible for the reduction or waiver of a civil penalty if: (1) The violation involves willful or criminal conduct; (2) the small entity has not made a good faith effort to comply with the law; or (3) the violation poses a serious threat to health, safety, or the environment. These exclusions are given as examples in SBREFA and are consistent with the President's memorandum on waiver of penalties for small businesses.

The Department's policy statement includes a non-exclusive list of factors that DOE may weigh in deciding whether to reduce or waive a civil penalty that has been assessed against an eligible small entity. DOE will consider a reduction or waiver of a civil penalty in the following circumstances: (1) The small entity has not been subject to previous enforcement actions for statutory or regulatory violations; (2) the small entity has a low degree of culpability (e.g., violation was committed inadvertently or without knowledge of requirements); (3) the small entity cooperated fully during the investigation that revealed the violation; (4) the small entity engaged in subsequent corrective actions to mitigate the effects of the violation and prevent future violations; (5) the small entity reasonably relied on misleading or erroneous advice given by a DOE officer or employee; and (6) the small entity is unable financially to pay the penalty. Each factor does not necessarily need to be present for a small entity to qualify for reduction or waiver of a civil penalty, and some factors may be weighed more heavily than others, depending on the particular circumstances.

The Department does not intend this policy statement on reduction and waiver of civil penalties for small entities to change its current policies for enforcing nuclear safety requirements under 10 CFR part 820. This statement of policy complements, and is not intended to be inconsistent with, the statement of enforcement policy in part 820. In enforcing nuclear safety requirements, the Department encourages and rewards contractors who promptly identify, report, and correct non-compliant conditions before they become serious health, safety or environmental threats. See General Statement of Enforcement Policy, appendix A to 10 CFR part 820, ''Procedural Rules for DOE Nuclear Activities.'' The Department's policy is to reduce significantly the base civil penalty for a DOE contractor who identifies and promptly reports a violation to DOE. On the other hand, the policy provides for setting a civil penalty assessment above the base civil penalty if a covered contractor fails to promptly report and correct potential violations.

The DOE policy concerning the reduction and waiver of civil penalties for small entities does not create a right or remedy for any person. The Department reserves the right to reduce or waive civil penalties in circumstances other than those listed under the policy statement if it is legally permissible and in the public interest to do so.

IV. Congressional Notification

Consistent with the Small Business Regulatory Enforcement Fairness Act of 1996, DOE will submit to Congress a report regarding the issuance of this policy statement prior to the effective date. The report will note that the Office of Management and Budget has determined that this statement of policy does not constitute a ''major rule'' under that Act. 5 U.S.C. 804(2).

Issued in Washington, D.C., on May 12, 1998.

Mary Anne Sullivan,

Acting General Counsel.

Statement of Policy on Compliance Guidance and Reduction and Waiver of Civil Penalties for Small Entities

The Department of Energy (DOE or Department) has issued this policy statement to comply with sections 213 and 223 of the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), which was enacted as title II of Pub. L. 104–121. Section 213(b) of SBREFA, 5 U.S.C. 601 note, requires agencies that regulate the activities of small entities to establish a program for responding to inquiries from small entities concerning information on, and advice about, compliance with statutory and regulatory requirements. Section 223 of SBREFA, 5 U.S.C. 601 note, requires each agency regulating the activities of small entities to establish a program or policy to provide for the reduction, and under appropriate circumstances, for the waiver of civil penalties for violations of statutory or regulatory requirements by small entities.

I. Compliance Guidance to Small Entities

The following policies apply to inquiries from small entities concerning compliance with applicable statutes and regulations:

1. Each DOE office with authority to bring enforcement actions against small entities for violation of statutory or regulatory requirements (hereafter ''DOE office'') should answer inquiries by small entities concerning the application of statutes and regulations to specific facts or circumstances, unless answering an inquiry may interfere with an ongoing investigation or proceeding or otherwise would not be appropriate or practicable.

2. DOE offices should require a small entity that requests DOE to provide written guidance applying the law to facts to state the specific facts and circumstances relevant to its request and to identify the pertinent statute or regulation and the related question on which guidance is sought.

3. DOE offices should consult with Department legal counsel, and any other office or agency with an interest in the matter, before responding in writing to a request by a small entity for guidance regarding how a statute or regulation applies to particular facts and circumstances.

4. DOE offices should deny a request by a small entity for compliance guidance if the small entity has not

[1] DOE recently revised the civil penalty amounts specified in the PAAA and other statutes to comply with the Federal Civil Penalties Inflation Adjustment Act of 1990, 28 U.S.C. 2461 note, as amended by the Debt Collection Improvement Act of 1996, Pub. L. 104–134. See Final Rule, Inflation Adjustment of Civil Monetary Penalties, 62 FR 46181 (Sept. 2, 1997).

provided sufficient information upon which to base a response, or for other good cause.

II. Reduction and Waiver of Civil Penalites for Small Entities

1. DOE offices shall consider on a case-by-case basis whether to reduce or waive an initial assessment of a civil penalty against a small entity for violation of a statutory or regulatory requirement in accordance with the policies that follow.

2. A small entity that has been assessed a civil penalty by DOE shall not be eligible for a reduction or waiver of the penalty if any of the following apply:

(a) The violation involves willful or criminal conduct by the small entity;

(b) The small entity has not made a good faith effort to comply with the law; or

(c) The violation poses a serious threat to health, safety, or the environment.

3. Subject to the exclusions in paragraph 2, DOE offices may consider the following factors in deciding whether to reduce or waive a civil penalty against a small entity:

(a) The small entity's history of legal or regulatory violations;

(b) The degree of culpability of the small entity when it committed the violation;

(c) The extent to which the small entity cooperated during the investigation;

(d) The extent to which the small entity engaged in subsequent corrective actions to mitigate the effects of the violation and prevent future violations;

(e) The extent to which the small entity reasonably relied on misleading or erroneous advice given by a DOE employee;

(f) The ability of the small entity to pay the civil penalty, in whole or in part; and

(g) Any other relevant fact.

4. DOE offices should require a person requesting the reduction or waiver of a civil penalty under this policy to establish that it meets the definition of ''small entity'' set forth in Section III of this statement of policy.

5. This policy on reduction and waiver of civil penalties for small entities complements, and does not supersede, the general statement of enforcement policy in 10 CFR part 820, appendix A, which applies to enforcement of nuclear safety requirements.

6. The Department reserves the right to reduce or waive civil penalties in appropriate individual circumstances where it determines that a reduction or waiver is permitted by law and warranted by the public interest.

III. Definition of ''Small Entity''

For purposes of this policy, *small entity* means a ''small business,'' ''small organization,'' or ''small governmental jurisdiction'' as defined by the Regulatory Flexibility Act. 5 U.S.C. 601. The Regulatory Flexibility Act definitions are as follows:

(1) Small business has the same meaning as the term ''small business concern'' under section 3 of the Small Business Act, unless (DOE), after consultation with the Office of Advocacy of the Small Business Administration and after opportunity for public comment, establishes one or more definitions of such term which are appropriate to the activities of (DOE) and publishes such definition(s) in the **Federal Register**;

(2) Small organization means any not-for-profit enterprise which is independently owned and operated and is not dominant in its field, unless (DOE) establishes, after opportunity for public comment, one or more definitions of such term which are appropriate to the activities of (DOE) and publishes such definition(s) in the **Federal Register**; and

(3) Small governmental jurisdiction means governments of cities, counties, towns, townships, villages, school districts, or special districts, with a population of less than fifty thousand, unless (DOE) establishes, after opportunity for public comment, one or more definitions of such term which are appropriate to the activities of (DOE) and which are based on such factors as location in rural or sparsely populated areas or limited revenues due to the population of such jurisdiction, and publishes such definition(s) in the **Federal Register**.

[FR Doc. 98–13587 Filed 5–20–98; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP98–530–000]

Equitrans, L.P.; Notice of Request Under Blanket Authorization

May 15, 1998.

Take notice that on May 8, 1998, Equitrans, L.P. (Equitrans), 3500 Park Lane, Pittsburgh, PA 15275, filed in Docket No. CP98–530–000, a request, pursuant to Sections 157.205 and 157.211 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.205 and 157.211), for authorization to install a tap, metering, electronic flow measurement, and appurtenant facilities for the delivery of transportation gas to AFG Industries, Inc. (AFG) in Flemington District, Taylor County, West Virginia, under Equitrans' blanket certificate authorization issued in Docket No. CP83–508–000, pursuant to Section 7 of the Natural Gas Act, all as more fully set forth in the request which is on file with the Commission and open to public inspection.

Specifically, Equitrans seeks authorization to install a tap connection on its existing pipeline, Number GST–902. Equitrans relates that it will have a ten year firm transportation agreement with AFG. Equitrans states that the annual delivered volumes will be approximately 1,642,000 Dth, with a peak day volume of 5,000 Dth and a daily contractual obligation of 4,300 Dth. Equitrans asserts that all volumes delivered to AFG will be within contractually permissible levels.

Equitrans states that this change is not prohibited by an existing tariff and that it has sufficient capacity to accomplish the deliveries specified without detriment or disadvantage to its other customers. Equitrans estimates the cost to construct the facilities at approximately $127,200, a portion of which will be reimbursed by AFG to Equitrans. Equitrans has sent a copy of this request to the West Virginia Public Service Commission.

Any person or the Commission's staff may, within 45 days after issuance of the instant notice by the Commission, file with the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, pursuant to Rule 214 of the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention and pursuant to Section 157.205 of the Regulations under the Natural Gas Act (18 CFR 157.205) a protest to the request. If no protest is filed within the time allowed therefore, the proposed activity shall be deemed to be authorized effective the day after the time allowed for filing a protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request shall be treated as an application for authorization pursuant to Section 7 of the Natural Gas Act.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13495 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2077–000–NY/VT]

New England Power Company; Notice of Scoping Meetings Pursuant to the National Environmental Policy Act of 1969 for an Applicant Prepared Environmental Assessment

May 15, 1998.

Pursuant to the Energy Policy Act of 1992, and as part of the license application, the New England Power Company (NEP) intends to prepare an Applicant Prepared Environmental Assessment (APEA) to file along with the license application, with the Federal Energy Regulatory Commission (Commission) for the Fifteen Mile Falls (FMF) Project No. 2077. The license for the project expires on July 31, 2001.

In October 1995, NEP initiated the cooperative consultation process, and in December 1995, state and federal agencies, local interests, and nongovernmental organizations (NGOs), undertook a cooperative effort for the relicensing of the FMF Project. The process involved identification of environmental issues associated with the relicensing of the FMF Project, including: a public informational meeting in February 1996, a project site visit for agencies/stakeholders, and a public meeting to solicit comments on the Initial Consultation Document (ICD) in June 1996.

As a result of the cooperative consultation process, settlement negotiation meetings were conducted during the spring of 1997, resulting in a signed Settlement Agreement on August 6, 1997.

NEP obtained support from the parties involved in the cooperative process and Settlement Agreement to pursue the APEA process for the relicensing of the FMF Project. On March 9, 1998, NEP requested, and on April 22, 1998, obtained FERC's approval to enter the APEA process. As part of the APEA process, NEP has prepared a Scoping Document I (SDI), which provides information on the scoping process, APEA schedule, background information, environmental issues, and proposed project alternatives.

The purpose of this notice is to: (1) advise all parties as to the proposed scope of the environmental analysis, including cumulative effects, and to seek additional information pertinent to this analysis; and (2) advise all parties of their opportunity for comment.

Scoping Process

The purpose of the scoping process is to identify significant issues related to the proposed action and to determine what issues should be addressed in the document to be prepared pursuant to the National Environmental Policy Act of 1969 (NEPA). The SDI will be circulated to enable appropriate federal, state, and local resource agencies, Indian tribes, NGOs, and other interested parties to participate in the scoping process. SDI provides a brief description of the proposed action, project alternatives, the geographic and temporal scope of a cumulative effects analysis, and a list of issues.

Scoping Meetings and Site Visit

NEP and FERC staff will conduct two scoping meetings and a site visit. All interested individuals, organizations, and agencies are invited to attend and assist in identifying the scope of environmental issues that should be analyzed in the APEA.

The public scoping meeting will be held on June 4, 1998, from 7:00 to 9:00 pm at the Littleton Opera House, Main Street, Littleton, NH. The agency scoping meeting will be held on June 5, 1998, from 9:30 to 12:00 am at the North Country Council Conference Room, 107 Glessner Road, Bethlehem, NH. The site visit will commence at 9:30 am on June 4, 1998. Those persons interested should meet at Moore Visitor Center, Rtes. 135/18, Littleton, NH. For more details, interested parties should contact John Ragonese, NEP, (603)–443–9229, prior to the meeting date.

Objectives

At the scoping meetings, NEP and FERC staff will: (1) summarize the environmental issues identified for analysis in the APEA; (2) solicit from the meeting participants all available information, especially quantified data, on the resources at issue, and (3) encourage statements from experts and the public on issues that should be analyzed in the APEA. Individuals, organizations, and agencies with environmental expertise and concerns are encouraged to attend the meetings and to assist in defining and clarifying the issues to be addressed.

Meeting Procedures

The meeting will be conducted according to the procedures used at Commission scoping meetings. Because this meeting will be a NEPA scoping meeting, the Commission will not conduct another scoping meeting when the application and APEA are filed with the Commission in Spring 1999.

The meetings will be recorded by a stenographer and become a part of the formal record of the Commission proceeding on the FMF Project. Individuals presenting statements at the meetings will be asked to identify themselves for the record. Speaking time allowed for individuals will be determined before each meeting, based on the number of persons wishing to speak and the approximate amount of time available for the session. Persons choosing not to speak but wishing to express an opinion, as well as speakers unable to summarize their positions within their allotted time, may submit written statements for inclusion in the public record no later than June 19, 1998.

All filings should contain an original and 8 copies. Failure to file an original and 8 copies may result in appropriate staff not receiving the benefit of your comments in a timely manner. All comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, and should clearly show the following captions on the first page: Fifteen Mile Falls Project, FERC No. 2077. A copy of each filing should also be sent to John Ragonese, New England Power Company, 407 Miracle Mile, Suite 2, Lebanon, NH 02766.

Based on all written comments, a Scoping Document II (SDII) may be issued. SDII will include a revised list of issues, based on the scoping sessions.

For further information regarding the APEA scoping process, please contact William Guey-Lee, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC, 20426 at (202) 219–2794, or John Ragonese, New England Power Company, at (603) 443–9229.

Linwood A. Watson, Jr.

Acting Secretary.

[FR Doc. 98–13482 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP98–531–000]

NorAm Gas Transmission Company; Notice of Request Under Blanket Authorization

May 15, 1998.

Take notice that on May 11, 1998, NorAm Gas Transmission Company (NGT), 1600 Smith Street, Houston, Texas 77002, filed in Docket No. CP98–531–000 a request pursuant to Sections

157.205 and 157.211 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.205, 157.211) for authorization to construct and operate certain facilities in Webster Parish, Louisiana, under NGT's blanket certificate issued in the Docket No. CP82–384–000 and CP82–384–001 pursuant to Section 7 of the Natural Gas Act, all as more fully set forth in the request that is on file with the Commission and open to public inspection.

NGT specifically requests authority to install a 3-inch tap, 3-inch regulatory setting, and 6-inch meter station, on NGT's Line S in Webster Parish, Louisiana, under Subpart G of Part 284 of the Commission's Regulation. NGT states that this meter station is being constructed to provide service to Arkla, a distribution division of NorAm Energy Corp. (Arkla). NGT states the estimated volumes to be delivered through these facilities are approximately 3,008,086 MMBtu annually and 14,857 MMBtu on a peak day. NGT states the cost of the facilities to be installed is $64,198, and that $59.375 will be reimbursed by Arkla. NGT also states that Arkla will install 550 feet of 6-inch pipe to connect this point to an addition to its Louisiana distribution system which it is acquiring from Louisiana-Nevada Gas Transit Company.

Any person or the Commission's staff may, within 45 days after issuance of the instant notice by the Commission, file pursuant to Rule 214 of the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention and pursuant to Section 157.205 of the Regulations under the Natural Gas Act (18 CFR 157.205) a protest to the request. If no protest is filed within the time allowed therefor, the proposed activity shall be deemed to be authorized effective the day after the time allowed for filing a protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request shall be treated as an application for authorization pursuant to Section 7 of the Natural Gas Act.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13496 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP98–533–000]

Northern Natural Gas Company; Notice of Request Under Blanket Authorization

May 15, 1998.

Take notice that on May 11, 1998, Northern Natural Gas Company (Northern), 1111 South 103rd Street, Omaha, Nebraska 68124–1000, filed in Docket No. CP98–525–000 a request pursuant to Sections 157.205, 157.212 and 157.216 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.205, 157.212, 157.216) for authorization to upgrade an existing delivery point located in Dodge County, Minnesota, to accommodate natural gas deliveries to U.S. Energy Services, Inc. (USEI), under Northern's blanket certificate issued in Docket No. CP82–401–000 [1] pursuant to Section 7 of the Natural Gas Act, all as more fully set forth in the request that is on file with the Commission and open to public inspection.

Northern states that it requests authority to upgrade this delivery point to accommodate natural gas deliveries to USEI under currently effective throughput service agreements. Northern asserts that USEI has requested the upgrade of the existing delivery point to provide increased natural gas service to the Al-Corn town border station. The estimated incremental volumes proposed to be delivered to USEI at this delivery point are 400 MMBtu on a peak day and 146,000 MMBtu on an annual basis. Northern has stated that the estimated cost to upgrade the delivery point is $24,500.

Any person or the Commission's staff may, within 45 days after issuance of the instant notice by the Commission, file pursuant to Rule 214 of the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention and pursuant to Section 157.205 of the Regulations under the Natural Gas Act (18 CFR 157.205) a protest to the request. If no protest is filed within the time allowed therefor, the proposed activity shall be deemed to be authorized effective the day after the time allowed for filing a protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request shall be treated as an application for authorization pursuant to Section 7 of the Natural Gas Act.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13480 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

[1] *See*, 20 *FERC* ¶ 62,410 (1982).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP98–524–000]

Northern Natural Gas Company; Notice of Request Under Blanket Authorization

May 15, 1998

Take notice that on May 6, 1998, Northern Natural Gas Company, (Northern), 1111 South 103rd Street, Omaha, Nebraska 68124–1000, filed in Docket No. CP98–524–000 a request pursuant to Sections 157.205 and 157.216 of the Commission's Regulations under the Natural Gas Act (18 CFR 157.205, 157.216) for authorization to abandon and remove three town border stations (TBSs), all as more fully set forth in the request that is on file with the Commission and open to public inspection.

Northern proposes to abandon and remove one TBS in Saunders County, Nebraska, and two TBSs in Rice County, Minnesota. Northern constructed the subject facilities pursuant to 2.55 of the regulations and proposes to abandon them because the gas service downstream of the TBSs have been discontinued and that no other use exist for the facilities.

Northern states that the abandonment will not result in any disruption or disadvantage any of Northern's customers.

Any person or the Commission's staff may, within 45 days after issuance of the instant notice by the Commission, file pursuant to Rule 214 of the Commission's Procedural Rules (18 CFR 385.214) a motion to intervene or notice of intervention and pursuant to Section 157.205 of the Regulations under the Natural Gas Act (18 CFR 157.205) a protest to the request. If no protest is filed within the time allowed therefore, the proposed activity shall be deemed to be authorized effective the day after the time allowed for filing a protest. If a protest is filed and not withdrawn within 30 days after the time allowed for filing a protest, the instant request shall be treated as an application for

authorization pursuant to Section 7 of the Natural Gas Act.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13490 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP98–526–000]

Panhandle Eastern Pipe Line Company; Notice of Application

May 15, 1998.

Take notice that on May 6, 1998, Panhandle Eastern Pipe Line Company (Panhandle), P.O. Box 1642, Houston, Texas 77251–1642, filed an application in Docket No. CP98–526–000 pursuant to section 7(b) of the Natural Gas Act, as amended, and Part 157 of the Commission's Regulations for permission and approval to abandon by removal, the Bison Compressor Station, including the two compressor units, and appurtenant facilities located in Kingfisher County, Oklahoma, all as more fully set forth in the application on file with the Commission and open to public inspection.

The Bison Compressor Station is equipped with two 1,674 compressor units (U–340 and U–341), with compression horsepower totaling 3,348 (hp). Panhandle states that this compression is no longer required to meet its customers' delivery requirements. Panhandle also requests authorization to abandon in place the fencing, engine room and warehouse buildings, overhead crane, yard lights, other minor items, and all below-grade piping. Panhandle will transfer title of these items to the landowners upon abandonment authorization. The landowners have agreed to accept the facilities Panhandle proposes to abandon in place, by Letter of Agreement between Panhandle and Woods Acres, Inc. on February 27, 1998. All piping, other than road crossings, to be retired and abandoned in place will be cut 30 inches below grade, filled with water and capped. Road crossings will be filled with concrete slurry instead of water.

Any person desiring to be heard or to make any protest with reference to said application should on or before June 5, 1998, file with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214) and 385.211 and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no motion to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that a grant of the certificate is required by the public convenience and necessity. If a motion of leave to intervene is timely filed or if the Commission on its motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Panhandle to appear or be represented at the hearing.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13494 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP98–193–001]

Shell Gas Pipeline Company; Notice of Proposed Changes in FERC Gas Tariff

May 14, 1998.

Take notice that on May 8, 1998, Shell Gas Pipeline Company (SGPC) tendered for filing an amendment to its filing in Docket No. RP98–193–000, as part of its FERC Gas Tariff, Original Volume No. 1, a revised title sheet proposed to become effective May 24, 1998.

SGPC states that the purpose of this filing is to reflect an address and telephone change for the corporate office of SGPC.

Any person desiring to protest this 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 as provided in Section 154.210 of the Commission's Regulations. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13481 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP98–522–000]

Texas Gas Transmission Corporation Columbia Gulf Transmission Company; Notice of Application

May 15, 1998.

Take notice that on May 5, 1998, Texas Gas Transmission Corporation (Texas Gas) P.O. Box 20008, Owensboro, Kentucky 42304, and Columbia Gulf Transmission Company (Columbia Gulf) P.O. Box 683, Houston, Texas 77001–0683, filed a joint application for Texas Gas to abandon by transfer, to Columbia Gulf, Texas Gas' interest in certain jointly-owned supply lateral facilities, and appurtenances, in the Eugene Island and Vermilion Areas, Offshore Louisiana, and for Columbia Gulf to acquire and own Texas Gas' interest in such facilities, all as more fully set forth in the application on file with the Commission and open to public inspection.

Texas Gas states that the facilities were originally constructed and operated jointly with Columbia Gulf to support its merchant function; however, due to the termination of the related third-party transportation agreements, Texas Gas no longer has a firm transportation commitment involving the facilities. As such, Texas Gas wishes to abandon these facilities to streamline its transmission operations. Columbia Gulf states that any shippers desiring access to the supplies attached to these laterals will be able to obtain transportation service from Columbia Gulf, thus none of the interruptible shippers currently utilizing the Texas Gas' capacity in the subject facilities will be subject to a diminution or termination of service.

Any person desiring to be heard or to make any protest with reference to said

application should on or before June 5, 1998, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214 or 385.211) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Take further notice that, pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by Sections 7 and 15 of the Natural Gas Act and the Commission's Rules of Practice and Procedure, a hearing will be held without further notice before the Commission or its designee on this application if no motion to intervene is filed within the time required herein, if the Commission on its own review of the matter finds that permission and approval for the proposed abandonment are required by the public convenience and necessity. If a motion for leave to intervene is timely filed, or if the Commission on its own motion believes that a formal hearing is required, further notice of such hearing will be duly given.

Under the procedure herein provided for, unless otherwise advised, it will be unnecessary for Texas Gas and Columbia Gulf to appear or be represented at the hearing.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13493 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. SA98–83–000]

The Trees Oil Company; Notice of Petition for Adjustment

May 15, 1998.

Take notice that on May 7, 1998, The Trees Oil Company (Trees) filed a petition, pursuant to section 502(c) of the Natural Gas Policy Act of 1978, for relief from making Kansas ad valorem tax refunds to Northern Natural Gas Company (Northern). The refunds are required by the Commission's September 10, 1997 order, in Docket No. RP97–369–000 *et al.*,[1] on remand from the D.C. Circuit Court of Appeals,[2] that directed First Sellers to make Kansas ad valorem tax refunds, with interest, for the period from 1983 to 1988. Alternatively, if it is not relieved from making the subject refunds, Trees requests that the Commission permit Trees to amortize its refund obligation over a 5-year period. Trees petition is on file with the Commission and open to public inspection.

Trees states that Northern sent Trees a Statement of Refunds Due for $192,815.47 in principal and $301,471.37 in interest, computed through December 31, 1997, for a total of refund liability of $494,286.84. Trees states that the Northern Statement covers seven wells, from which Trees made sales to Northern from 1983 to July 1, 1987. Trees asserts that the Statement includes an amount that Trees previously refunded to Northern [3] and Kansas ad valorem tax reimbursements on one well (the Warner well) that did not result in a price in excess of the applicable maximum lawful price (MLP).

Trees also states that during the applicable 1983–1987 period, 37.5 percent of the working interest in these wells was owned by a Pennsylvania Trust which was subsequently terminated, liquidated, and closed in 1991. Trees asserts that the Kansas ad valorem tax reimbursements distributed to this trust are unrecoverable, and that, once the necessary revisions are made to remove (a) the previously refunded principal and interest, (b) the Kansas ad valorem taxes that did not exceed the applicable MLP, and (c) the unrecoverable Pennsylvania Trust reimbursements, Trees refund liability consists of $99,611.52 in principal and $162,013.50 in interest, computed through December 31, 1997.

Trees also suggests that this $99,611.52 amount should be further reduced because it: 1) includes the principal and interest on pre-October 1983 production, the liability for which has been disputed before the U.S. Court of Appeals for the Fifth Circuit in *Anadarko Petroleum Corporation* v. *FERC* and *Union Pacific Resources Company* v. *FERC*, Case No. 98–60043; and (2) includes unrecoverable royalty amounts. Trees asserts that when the reimbursements attributable to pre-October 1983 production are excluded, along with the royalties attributable to the Pennsylvania Trust's working interest, the principal amount of its refund obligation to Northern is $80,538.82.

Trees also states that it is a small ''mother and daughter operation'' with no other administrative personnel. Trees explains that the subject wells were priced at the relatively low, NGPA section 104, flowing gas rate, which provided Trees with little, if any, income during the period from 1983–1987. Trees includes condensed December 31, 1983–1987 income statements to support its assertions, and states that the revenues shown on these statements include revenues from Trees' other oil and gas interests, and that the expenses include (a) its own share of the operating costs, (b) intangible drilling costs, (c) administrative costs, including salaries, rent, payroll taxes, and other office expenses, and (d) other expenses, including travel costs, seminars, licenses, and legal fees. Trees contends that, because these estimates show losses for four of the five years, despite small salaries and little, if any, drilling and exploration expense, they demonstrate how important the tax reimbursements were to Trees' economic viability and survivability during that period.

Trees also provides another condensed income statement for the year ending December 31, 1997, and notes that it plans to drill five wells in 1998 and convert a well to salt water disposal. Trees states that it is pursuing this drilling program in part out of consideration of the implied obligations of the leases for further development and to protect against drainage. Trees contends that this drilling program will tax its cash flow and financial resources, regardless of whether Trees is required to make Kansas ad valorem tax refunds. Trees adds that two of the committed wells have already been drilled, and that the total cost to drill and equip all five wells (if they are successful), and to convert the other, will be approximately $1,900,000, of which Trees' share of the costs will be $475,000. Trees contends that it has no monetary cushion to pay its drilling costs and also pay the Kansas ad valorem tax refunds.

Therefore, Trees contends that it should be relieved from having to refund any of these tax reimbursements. In the alternative, Trees requests permission to amortize its refund obligation over a 5-year period.

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[1] See 80 FERC ¶ 61,264 (1997); Order Denying Rehearing issued January 28, 1998, 82 FERC ¶ 61,058 (1998).

[2] *Public Service Company of Colorado* v. *FERC*, 91 F.3d 1478 (D.C. 1996), cert. denied, Nos. 96–954 and 96–1230 (65 U.S.L.W. 3751 and 3754, May 12, 1997).

[3] Trees explains that Northern's Statement includes a payment of $26,083.44 that Northern made to Trees on April 7, 1989, for 1988 taxes, an amount that Trees subsequently refunded, with interest, on July 1, 1994.

Any person desiring to be heard or to make any protest with reference to said petition should on or before 15 days after the date of publication in the **Federal Register** of this notice, file with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, a motion to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 385.214, 385.211, 385.1105, and 385.1106). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding. Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a motion to intervene in accordance with the Commission's Rules.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13487 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP97–156–007]

Viking Gas Transmission Company; Notice of Request for Extension of Time

May 15, 1998.

Take notice that on April 30, 1998, Viking Gas Transmission Company (Viking) filed for an extension of implementation dates for computer-related capacity release GISB standards.

Viking requests the Commission to grant Viking an extension of time to June 1, 1999, to implement the computer-related capacity release GISB standards. Viking says it needs additional time to test and to implement its capacity release computer components. Viking claims its ability to test and to implement its capacity release computer components has been delayed due to complications that arose in conjunction with its conversion to an Internet-based EBB in place of a dial-up EBB.

Any person desiring to protest said filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Section 385.211 of the Commission's Rules and Regulations. All such protests should be filed on or before May 22, 1998. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13488 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. PR98–12–000]

Enogex Inc.; Notice of Petition for Rate Approval

May 15, 1998.

Take notice that on May 1, 1998 Enogex Inc. (Enogex) filed pursuant to Section 284.123(b)(2) of the Commission's Regulations, 18 CFR 284.123(b)(2), a petition for rate approval to establish new rates for interruptible transportation services which Enogex provides under Section 311(a)(2) of the Natural Gas Policy Act of 1978. The proposed maximum rate for interruptible transportation service is $0.5470 per MMBtu, to be effective May 1, 1998.

Enogex also proposes an optional monetary settlement (cash out) for quantities of gas which are below nominated delivery amounts (underdeliveries) or greater than nominated delivery amounts (overdeliveries), to reduce the number of priority categories for curtailment purposes, and to make certain minor changes, clarifications and corrections to the Enogex Statement of Enogex Inc. in Compliance with 18 CFR Part 284. Enogex has submitted a revised Statement in Compliance with its petition for rate approval, to be effective June 1, 1998.

Pursuant to Section 284.123(b)(2)(ii) of the Commission's Regulations, if the Commission does not act within 150 days of the filing date, the rates Enogex proposes will be deemed to be fair and equitable and not in excess of an amount which interstate pipelines would be permitted to charge for similar transportation service. The Commission may, prior to the expiration of the 150 day period, extend the time for action or institute a proceeding to afford parties an opportunity for written comments and for the oral presentation of views, data and arguments.

Any person desiring to participate in this rate proceeding must file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Sections 385.214 and 385.211 of the Commission's Rules of Practice and Procedure. All such motions or protests must be filed with the Secretary of the Commission on or before June 1, 1998. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of this application are on file with the Commission and are available for public inspection.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13486 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project Nos. 10865–001 and 11495–000]

Warm Creek Hydro, Inc. and Nooksack River Hydro, Inc.; Notice of Site Visit

May 15, 1998.

The Federal Energy Regulatory Commission (Commission) has received an application for license for the proposed Warm Creek Project No. 10865 and Clearwater Creek Project No. 11495. The projects are located in Whatcom County, Washington.

The Commission issued a notice to prepare an Environmental Impact Statement (EIS) on the hydroelectric projects in accordance with the National Environmental Policy Act.

The Commission's staff will visit the project site on Wednesday, June 10, 1998. The site visit will begin at 9:00 a.m. at the Acme Cafe on Highway 9 in Acme, Washington. Interested individuals, organizations, and agencies are invited to attend the site visit to gain a better understanding of the proposed projects. People interested in attending the site visit should provide their own transportation.

If you have any questions please contact Tim Looney at (202) 219–2852.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13485 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RP98–159–001]

Williams Gas Pipelines Central; Notice of Refund Report

May 15, 1998.

Take notice that on May 13, 1998, Williams Gas Pipelines Central, Inc. (Williams), filed a report of refunds made to Shippers pursuant to a Commission order issued April 13, 1998 (April 13 order), in Docket No. RP98–159–000.

Williams states that on March 11, 1998, it filed its annual report of net revenues received from cash-out activity for the twelve-month period ending September 30, 1997. The report proposed to make such refunds to Shippers listed on the refund report, including interest from April 1, 1998 through the date of the refund, upon Commission approval of the report of refunds. The April 13 order required Williams to make refunds to its customers as proposed in the March 11 filing within 30 days of the order. The interest calculation has been updated from the original report to include interest from April 1, 1998 through May 12, 1998.

Williams states that a copy of its filing was served on all Shippers receiving a refund, all participants listed on the service lists maintained by the Commission in the docket referenced above and interested state commissions.

Any person desiring to protest this filing should file a protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Section 385.211 of the Commission's Rules and Regulations. All such protests must be filed on or before May 22, 1998. 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. Copies of this filing are on file with the Commission and are available for public inspection in the Public Reference Room.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13489 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER97–3561–000, et al.]

Virginia Electric and Power Company, et al.; Electric Rate and Corporate Regulation Filings

May 14, 1998.

Take notice that the following filings have been made with the Commission:

1. Virginia Electric and Power Company

[Docket No. ER97–3561–000]

Take notice that on May 11, 1998, Virginia Electric and Power Company (Virginia Power), tendered for filing the Settlement Agreement between Virginia Electric and Power Company, North Carolina Eastern Municipal Power Agency, North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, Inc., and Virginia Municipal Electric Association No. 1. The Settlement is to be treated as an Offer of Settlement as to The Office of Attorney General of the Commonwealth of Virginia, Division of Consumer Counsel.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

2. Econnergy Energy Company, Inc.

[Docket No. ER98–2553–000]

Take notice that on May 11, 1998, Econnergy Energy Company, Inc. (Econnergy), filed an amended petition to the commission for acceptance of Econnergy Rate Schedule FERC No. 1; the granting of certain blanket approvals, including the authority to sell electricity at market-based rates; and the waiver of certain Commission Regulations.

Econnergy intends to engage in wholesale electric power and energy purchases and sales as a marketer. Econnergy is not in the business of generating or transmitting electric power. Econnergy is not a subsidiary or affiliate of any other company.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

3. Alliant Service, Inc.

[Docket No. ER98–2938–000]

Take notice that on May 11, 1998, Alliant Services, Inc., tendered for filing executed Service Agreements for Firm and Non-Firm Point-to-Point Transmission Service, establishing Central Illinois Light Company as a point-to-point Transmission Customer under the terms of the Alliant Services, Inc., transmission tariff.

Alliant Services, Inc., requests an effective date of April 14, 1998, and accordingly, seeks waiver of the Commission's notice requirements.

A copy of this filing has been served upon the Public Service Commission of Wisconsin.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

4. Consolidated Edison Company of New York, Inc.

[Docket No. ER98–2943–000]

Take notice that on May 11, 1998, Consolidated Edison Company of New York, Inc. (Con Edison), tendered for filing revised tariff sheets establishing rates for retail transmission service and related ancillary services to be rendered pursuant to Con Edison's open access transmission tariff, FERC Electric Tariff, Original Volume No. 1. The proposed rates are based upon a revenue requirement stipulated by settlement in Con Edison's transmission rate case and are designed in accordance with a methodology which has been approved by the New York State Public Service Commission (PSCNY) in conjunction with Con Edison's retail access program.

Con Edison states that a copy of this filing has been served by mail upon the PSCNY and the parties to Docket Nos. ER98–1631 and OA96–138–000.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

5. MidAmerican Energy Company

[Docket No. ER98–2944–000]

Take notice that on May 11, 1998, MidAmerican Energy Company (MidAmerican), 666 Grand Avenue, Des Moines, Iowa 50303 submitted for filing with the Commission a Service Agreement dated April 29, 1998, with Montezuma Municipal Light and Power (Montezuma) entered into pursuant to MidAmerican's Rate Schedule for Power Sales, FERC Electric Tariff, Original Volume No. 5 (Tariff), and a Power Sales Agreement dated April 29, 1998, with Montezuma Municipal Light and Power entered into pursuant to the Service Agreement and the Tariff.

MidAmerican requests an effective date of May 1, 1998, for this Agreement, and accordingly seeks a waiver of the Commission's notice requirement. MidAmerican has served a copy of the filing on Montezuma, the Iowa Utilities Board, the Illinois Commerce Commission and the South Dakota Public Utilities Commission.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

6. MidAmerican Energy Company

[Docket No. ER98–2945–000]

Take notice that on May 11, 1998, MidAmerican Energy Company tendered for filing a proposed change in its Rate Schedule for Power Sales, FERC Electric Rate Schedule, Original Volume No. 5. The proposed change consists of certain reused tariff sheets consistent with the quarterly filing requirement.

MidAmerican states that it is submitting these tariff sheets for the purpose of complying with the requirements set forth in Southern Company Services, Inc., 75 FERC ¶ 61,130 (1996), relating to quarterly filings by public utilities of summaries of short-term market-based power transactions. The tariff sheets contain summaries of such transactions under the Rate Schedule for Power Sales for the applicable quarter.

MidAmerican proposes an effective date of the first day of the applicable quarter for the rate schedule change. Accordingly, MidAmerican requests a waiver of the 60-day notice requirement for this filing. MidAmerican states that this date is consistent with the requirements of the Southern Company Services, Inc., order and the effective date authorized in Docket No. ER96–2459–000.

Copies of the filing were served upon MidAmerican's customers under the Rate Schedule for Power Sales and the Iowa Utilities Board, the Illinois Commerce Commission and the South Dakota Public Utilities Commission.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

7. Alliant Service, Inc.

[Docket No. ER98–2946–000]

Take notice that on May 11, 1998, Alliant Services, Inc., tendered for filing an executed Service Agreements for firm and non-firm point-to-point transmission service, establishing Upper Peninsula Power Company as a point-to-point Transmission Customer under the terms of the Alliant Services, Inc., transmission tariff.

Alliant Services, Inc., requests an effective date of April 15, 1998, and accordingly, seeks waiver of the Commission's notice requirements. A copy of this filing has been served upon the Public Service Commission of Wisconsin.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

8. California Independent System Operator Corporation

[Docket No. ER98–2947–000]

Take notice that on May 11, 1998, the California Independent System Operator Corporation (ISO), tendered for filing a Meter Service Agreement for ISO Metered Entities between the ISO and Wheelabrator Martell, Inc. (Wheelabrator), for acceptance by the Commission.

The ISO is requesting a waiver of the 60-day prior notice requirement to allow the Meter Service Agreement to be made effective as of April 28, 1998.

The ISO states that this filing has been served on Wheelabrator and the California Public Utilities Commission.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

9. California Independent System Operator Corporation

[Docket No. ER98–2948–000]

Take notice that on May 11, 1998, the California Independent System Operator Corporation (ISO), tendered for filing a Scheduling Coordinator Agreement between the ISO and Modesto Irrigation District (Modesto), for acceptance by the Commission.

The ISO is requesting a waiver of the 60-day prior notice requirement to allow the Scheduling Coordinator Agreement to be made effective as of April 24, 1998.

The ISO states that this filing has been served on Modesto and the California Public Utilities Commission.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

10. California Independent System Operator Corporation

[Docket No. ER98–2949–000]

Take notice that on May 11, 1998, the California Independent System Operator Corporation (ISO), tendered for filing a Meter Service Agreement for Scheduling Coordinators between the ISO and Modesto Irrigation District (Modesto), for acceptance by the Commission.

The ISO is requesting a waiver of the 60-day prior notice requirement to allow the Meter Service Agreement to be made effective as of April 21, 1998.

The ISO states that this filing has been served on Modesto and the California Public Utilities Commission.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

11. California Independent System Operator Corporation

[Docket No. ER98–2950–000]

Take notice that on May 11, 1998, the California Independent System Operator Corporation (ISO), tendered for filing a Participating Generator Agreement between Wheelabrator Martell, Inc. (Wheelabrator) and the ISO for acceptance by the Commission.

The ISO is requesting a waiver of the 60-day prior notice requirement to allow the Participating Generator Agreement to be made effective as of April 28, 1998.

The ISO states that this filing has been served upon Wheelabrator and the California Public Utilities Commission.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

12. California Independent System Operator Corporation

[Docket Nos. ER98–2951–000]

Take notice that on May 11, 1998, the California Independent System Operator Corporation (ISO), tendered for filing a Scheduling Coordinator Agreement between the ISO and the British Columbia Power Exchange Corporation (British Columbia PX), for acceptance by the Commission.

The ISO is requesting a waiver of the 60-day prior notice requirement to allow the Scheduling Coordinator Agreement to be made effective as of April 21, 1998.

The ISO states that this filing has been served on the British Columbia PX and the California Public Utilities Commission.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

13. California Independent System Operator Corporation

[Docket No. ER98–2952–000]

Take notice that on May 11, 1998, the California Independent System Operator Corporation (ISO), tendered for filing a Scheduling Coordinator Agreement between the ISO and the Bonneville Power Administration (BPA), for acceptance by the Commission.

The ISO is requesting a waiver of the 60-day prior notice requirement to allow the Scheduling Coordinator Agreement to be made effective as of April 30, 1998.

The ISO states that this filing has been served on BPA and the California Public Utilities Commission.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

14. Commonwealth Electric Company, Cambridge Electric Light Company

[Docket No. ER98–2953–000]

Take notice that on May 11, 1998, Commonwealth Electric Company (Commonwealth) and Cambridge Electric Light Company (Cambridge), collectively referred to as the ''Companies'', tendered for filing with the Federal Energy Regulatory Commission executed Service Agreements between the Companies and the following Market-Based Power Sales Customers (collectively referred to herein as the Customers):

Constellation Power Source, Inc.

These Service Agreements specify that the Customers have signed on to and have agreed to the terms and conditions of the Companies' Market-Based Power Sales Tariffs designated as Commonwealth's Market-Based Power Sales Tariff (FERC Electric Tariff Original Volume No. 7) and Cambridge's Market-Based Power Sales Tariff (FERC Electric Tariff Original Volume No. 9). These Tariffs, accepted by the FERC on February 27, 1997, and which have an effective date of February 28, 1997, will allow the Companies and the Customers to enter into separately scheduled short-term transactions under which the Companies will sell to the Customers capacity and/or energy as the parties may mutually agree.

The Companies request an effective date as specified on each Service Agreement.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

15. Southern Company Services, Inc.

[Docket No. ER98–2954–000]

Take notice that on May 11, 1998, Southern Company Services, Inc. (SCS), acting on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company (collectively referred to as Southern Company) filed four (4) umbrella service agreements for short-term firm point-to-point transmission service between SCS, as agent for Southern Company, and (i) OGE Energy Resources, (ii) Southern Illinois Power Cooperative, (iii) Southern Wholesale Energy, a Department of SCS, and (iv) Tractebel Energy Marketing, Inc., and one (1) service agreement for non-firm point-to-point transmission service executed between SCS, as agent for Southern Company, and Southern Illinois Power Cooperative under the Open Access Transmission Tariff of Southern Company.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

16. Louisville Gas & Electric Company

[Docket No. ER98–2955–000]

Take notice that on May 11, 1998, Louisville Gas and Electric Company (LG&E), tendered for filing an unexecuted Purchase and Sales Agreement between LG&E and Columbia Energy Power Marketing Corporation under LG&E's Rate Schedule GSS.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

17. Louisville Gas And Electric Company

[Docket No. ER98–2956–000]

Take notice that on May 11, 1998, Louisville Gas and Electric Company (LG&E), tendered for filing an unexecuted Purchase and Sales Agreement between LG&E and Avista Energy, Inc., under LG&E's Rate Schedule GSS.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

18. Consolidated Edison Company of New York, Inc.

[Docket No. ER98–2957–000]

Take notice that on May 11, 1998, Consolidated Edison Company of New York, Inc. (Con Edison), tendered for filing a Supplement to Con Edison Rate Schedule FERC No. 94, for transmission service for the Long Island Lighting Company (LILCO). The Rate Schedule provides for transmission of power and energy from the New York Power Authority's Blenheim-Gilboa station. The Supplement provides for a decrease in annual revenues under the Rate Schedule of $13,322.50. Con Edison has requested that this increase take effect on July 1, 1998.

Con Edison states that a copy of this filing has been served by mail upon LILCO.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

19. Arizona Public Service Company

[Docket No. ER98–2958–000]

Take notice that on May 11, 1998, Arizona Public Service Company filed a notice effective midnight the 31st day of August 1998, Rate Schedule FPC No. 58, effective date September 1, 1976 by FPC order dated January 19, 1977 and filed with the Federal Energy Regulatory Commission by Arizona Public Service Company is to be canceled.

Copies of the proposed cancellation has been served upon Wellton-Mohawk Irrigation & Drainage District and The Arizona Corporation Commission.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

20. Niagara Mohawk Power Corporation

[Docket No. ER98–2959–000]

Take notice that on May 11, 1998, Niagara Mohawk Power Corporation (ANMPC), tendered for filing with the Federal Energy Regulatory Commission an executed Transmission Service Agreement between NMPC and Pennsylvania Power & Light, Inc., (PP&L). This Transmission Service Agreement specifies that PP&L has signed on to and has agreed to the terms and conditions of NMPC's Open Access Transmission Tariff as filed in Docket No. OA96–194–000. This Tariff, filed with FERC on July 9, 1996, will allow NMPC and PP&L to enter into separately scheduled transactions under which NMPC will provide transmission service for PP&L as the parties may mutually agree.

NMPC requests an effective date of April 29, 1998. NMPC has requested waiver of the notice requirements for good cause shown.

NMPC has served copies of the filing upon the New York State Public Service Commission and PP&L.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

21. Idaho Power Company

[Docket No. ER98–2960–000]

Take notice that on May 11, 1998, Idaho Power Company (IPC), tendered for filing with the Federal Energy Regulatory Commission Service Agreements under Idaho Power Company's FERC Electric Tariff No. 6, Market Rate Power Sales Tariff, between Idaho Power Company and Equitable Power Services Co.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

22. Kansas City Power & Light Company

[Docket No. ER98–2974–000]

Take notice that on May 11, 1998, Kansas City Power & Light Company (KCPL), tendered for filing a Service Agreement dated April 13, 1998, between KCPL and Amoco Energy Trading Corporation. KCPL proposes an effective date of April 20, 1998, and

requests waiver of the Commission's notice requirement. This Agreement provides for the rates and charges for Non-Firm Transmission Service.

In its filing, KCPL states that the rates included in the above-mentioned Service Agreement are KCPL's rates and charges in the compliance filing to FERC Order No. 888–A in Docket No. OA97–636.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

23. Kansas City Power & Light Company

[Docket No. ER98–2975–000]

Take notice that on May 11, 1998, Kansas City Power & Light Company (KCPL), tendered for filing a Service Agreement dated April 13, 1998, between KCPL and Amoco Energy Trading Corporation. KCPL proposes an effective date of April 20, 1998, and requests waiver of the Commission's notice requirement. This Agreement provides for the rates and charges for Non-Firm Transmission Service.

In its filing, KCPL states that the rates included in the above-mentioned Service Agreement are KCPL's rates and charges in the compliance filing to FERC Order No. 888–A in Docket No. OA97–636.

Comment date: May 29, 1998, in accordance with Standard Paragraph E at the end of this notice.

24. Consumers Power Energy

[Docket No. ES97–7–004]

Take notice that on April 27, 1998, Consumers Power Energy (Consumers), filed an amendment to its application in this proceeding, under Section 204 of the Federal Power Act. The amendment seeks authorization to issue up to an additional $175 million of first-mortgage bonds, as security for other securities being issued by consumers. Consumers also requests a waiver of the Commission's competitive bid or negotiated placement requirements, under 18 CFR 34.2, Placement of Securities.

Comment date: May 26, 1998, in accordance with Standard Paragraph E at the end of this notice.

Standard Paragraph

E. Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 18 CFR 385.214). All such motions or protests should be filed on or before the comment date. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding.

Any person wishing to become a party must file a motion to intervene. Copies of these filings are on file with the Commission and are available for public inspection.

David P. Boergers,

Acting Secretary.

[FR Doc. 98–13560 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EG98–72–000, et al.]

Western Kentucky Energy Corp., et al.; Electric Rate and Corporate Regulation Filings

May 13, 1998.

Take notice that the following filings have been made with the Commission:

1. Western Kentucky Energy Corp.

[Docket No. EG98–72–000]

Take notice that on May 7, 1998, Western Kentucky Energy Corp. (WKEC), a Kentucky Corporation, with its principal place of business at P.O. Box 32010, 220 West Main Street, Louisville, Kentucky 40202, filed with the Federal Energy Regulatory Commission a letter (Clarification Letter), which clarifies the description of eligible facilities (Facilities) to be leased and/or operated by WKEC contained in Section II of its Application for Determination of Exempt Wholesale Generator Status which was filed with the Commission on April 30, 1998 (Application).

The Clarification Letter explains that Section II of the Application describes each of the four plants which WKEC proposed to lease and/or operate as having associated facilities, including step-up transformers and related equipment necessary to interconnect with the transmission facilities of Big Rivers Electric Corporation. WKEC states that the associated facilities which are transmission facilities are not a part of the Facilities to be leased and/or operated by WKEC, and at no time will WKEC own, lease, or operate any transmission facilities.

Comment date: June 3, 1998, in accordance with Standard Paragraph E at the end of this notice. The Commission will limit its consideration of comments to those that concern the adequacy or accuracy of the application.

2. Indeck Operations International, Inc.

[Docket No. EG98–74–000]

Take notice that on May 7, 1998, Indeck Operations International, Inc., a corporation organized and existing under the laws of the State of Illinois, with its address at 600 North Buffalo Grove Road, Suite 300, Buffalo Grove, Illinois 60089 (the Applicant), filed with the Federal Energy Regulatory Commission an application for determination of exempt wholesale generator (EWG) status pursuant to Part 365 of the Commission's Regulations.

The Applicant will be engaged directly and exclusively in the business of (A) operating an eligible facility located in Escuintla, Guatemala and eligible facilities located in Linden, Guyana and (B) based on agency relationships with the owners of each facility, selling electric energy at wholesale and retail.

The Escuintla Plant consists of a nominal 38 MW diesel generation facility utilizing heavy fuel oil as its primary fuel and No. 2 fuel oil as a backup fuel. The Guyana Plants consist of a nominal 27 MW steam-electric generating facility utilizing heavy fuel oil and a nominal 5 MW diesel generation facility utilizing distillate fuel.

Comment date: June 3, 1998, in accordance with Standard Paragraph E at the end of this notice. The Commission will limit its consideration of comments to those that concern the adequacy or accuracy of the application.

3. Phibro Inc.

[Docket Nos. EL98–45–000 and EC98–41–000]

Take notice that on May 6, 1998, Phibro Inc. (Phibro), tendered for filing a request that the Commission issue an order disclaiming jurisdiction over the forthcoming merger (Merger) of Citicorp with and into a subsidiary of Phibro's parent, Travelers Group Inc. (Travelers). In the alternative, Phibro requests that the Commission approve the proposed transaction and/or grant any other authorization the Commission may deem to be needed under Section 203 of the Federal Power Act. As explained in the Petition, the Merger will have no effect on the jurisdictional facilities, rates or services of Phibro and will be consistent with the public interest.

Phibro requests expeditious action on the application in order that there be no delay in the Merger.

Comment date: June 11, 1998, in accordance with Standard Paragraph E at the end of this notice.

4. Illinois Power Company

[Docket No. ER98–2150–001]

Take notice that on May 8, 1998, Illinois Power Company (Illinois Power), filed its refund report in compliance with the Commission's April 10, 1998, Letter Order in Docket No. ER98–2150–000.

Comment date: May 28, 1998, in accordance with Standard Paragraph E at the end of this notice.

5. Pacific Gas and Electric Company

[Docket No. ER98–2932–000]

Take notice that on May 8, 1998, Pacific Gas and Electric Company (PG&E), tendered for filing revisions to two agreements between PG&E and the City of Santa Clara, California (City or Santa Clara): (1) a revised Exhibit A–1 (forecast for the years 1998 and 1999) to Appendix A under PG&E Rate Schedule FERC No. 85; and (2) a change in the energy rate under PG&E Rate Schedule FERC No. 108 for the firm system power sale by PG&E to the City.

Copies of this filing were served upon City and the California Public Utilities Commission.

Comment date: May 28, 1998, in accordance with Standard Paragraph E at the end of this notice.

6. Houston Lighting & Power Company

[Docket No. ER98–2933–000]

Take notice that on May 8, 1998, Houston Lighting & Power Company (HL&P), tendered for filing an executed transmission service agreement (TSA), with LG&E Energy Marketing, Inc. (LG&E), for Non-Firm Transmission Service under HL&P's FERC Electric Tariff, Third Revised Volume No. 1, for Transmission Service To, From and Over Certain HVDC Interconnections. HL&P has requested an effective date of May 8, 1998.

Copies of the filing were served on LG&E and the Public Utility Commission of Texas.

Comment date: May 28, 1998, in accordance with Standard Paragraph E at the end of this notice.

7. Southern Indiana Gas and Electric Company

[Docket No. ER98–2934–000]

Take notice that on May 8, 1998, Southern Indiana Gas and Electric Company (SIGECO), tendered for filing one (1) service agreement for firm transmission service and one (1) service agreement for non-firm transmission service under Part II of its Transmission Services Tariff, both agreements with East Kentucky Power Cooperative, Inc.

Copies of the filing were served upon each of the parties to the service agreement.

Comment date: May 28, 1998, in accordance with Standard Paragraph E at the end of this notice.

8. Carolina Power & Light Company

[Docket No. ER98–2935–000]

Take notice that on May 8, 1998, Carolina Power & Light Company (CP&L), tendered for filing Service Agreements for Non-Firm Point-to-Point Transmission Service executed between CP&L and the following Eligible Transmission Customers: TransCanada Power Corp., and Entergy Power Marketing Corp.; and a Service Agreement for Short-Term Firm Point-to-Point Transmission Service with LG&E Power Marketing, Inc. Service to each Eligible Customer will be in accordance with the terms and conditions of Carolina Power & Light Company's Open Access Transmission Tariff.

Copies of the filing were served upon the North Carolina Utilities Commission and the South Carolina Public Service Commission.

Comment date: May 28, 1998, in accordance with Standard Paragraph E at the end of this notice.

9. Idaho Power Company

[Docket No. ER98–2936–000]

Take notice that on May 8, 1998, Idaho Power Company (IPC), tendered for filing with the Federal Energy Regulatory Commission Service Agreements under Idaho Power Company FERC Electric Tariff No. 5, Open Access Transmission Tariff, between Idaho Power Company and American Electric Power Service Corporation.

Comment date: May 28, 1998, in accordance with Standard Paragraph E at the end of this notice.

10. Pennsylvania Electric Company

[Docket No. ER98–2937–000]

Take notice that on May 8, 1998, Pennsylvania Electric Company (doing business as GPU Energy), filed a Transmission Agency Agreement with Allegheny Electric Cooperative, Inc., for transmission and certain ancillary services under the open access transmission tariff administered by PJM Interconnection, L.L.C.

Comment date: May 28, 1998, in accordance with Standard Paragraph E at the end of this notice.

11. Northeast Utilities Service Company

[Docket No. ER98–2939–000]

Take notice that on May 8, 1998, Northeast Utilities Service Company (NUSCO), tendered for filing, Service Agreements to provide Non-Firm Point-To-Point Transmission Service and Firm Point-To-Point Transmission Service to the Merchant Energy Group of the Americas, Inc., under the NU System Companies' Open Access Transmission Service Tariff No. 9.

NUSCO states that a copy of this filing has been mailed to the Merchant Energy Group of the Americas, Inc.

NUSCO requests that the Service Agreement become effective May 11, 1998.

Comment date: May 28, 1998, in accordance with Standard Paragraph E at the end of this notice.

12. Minnesota Power & Light Company

[Docket No. ER98–2940–000]

Take notice that on May 8, 1998, Minnesota Power & Light Company tendered for filing a signed Non-Firm Point-to-Point Transmission Service Agreement with Merchant Energy Group of the Americas, Inc., under its Non-Firm Point-to-Point Transmission Service to satisfy its filing requirements under this tariff.

Comment date: May 28, 1998, in accordance with Standard Paragraph E at the end of this notice.

Standard Paragraph

E. Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 18 CFR 385.214). All such motions or protests should be filed on or before the comment date. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of these filings are on file with the Commission and are available for public inspection.

David P. Boergers,

Acting Secretary.

[FR Doc. 98–13558 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. ER95–835–002, et al.]

Yankee Atomic Electric Company, et al. Electric Rate and Corporate Regulation Filings

May 15, 1998.

Take notice that the following filings have been made with the Commission:

1. Yankee Atomic Electric Company

[Docket No. ER95–835–002]

Take notice that on April 8, 1997, Yankee Atomic Electric Company tendered for filing an amended compliance report in the above-referenced docket.

Comment date: May 26, 1998, in accordance with Standard Paragraph E at the end of this notice.

2. Stratton Energy Associates, (a New York limited partnership)

[Docket Nos. EC98–42–000 and ER98–2931–000]

Take notice that on May 6, 1998, Stratton Energy Associates (SEA), a New York limited partnership, submitted petition for waiver of the Commission's rule restricting the filing of rate schedules to a period no less than 60 days, but not more than 120 days, prior to the date on which electric service is scheduled to commence and become effective under the rate schedule. 18 CFR 35.3. This request is made with regard to SEA's Rate Schedule No. 2, which is being filed simultaneously with such petition.

SEA further requests that the Commission waive its cost-of-service filing requirements applicable to initial rate filings, 18 CFR 35.12(b)(5), and to accept the SEA Rate Schedule No. 2 as filed. SEA also petitions the Commission to waive certain Commission rules that the Commission has previously determined not to be appropriately applicable to qualifying facilities such as the SEA facility.

Finally, SEA requests that the Commission find that the SEA Rate Schedule No. 2 constitutes a formula rate. Therefore, upon any acceptance of this rate by the Commission, any changes in charges due to the operation of the formula need not be filed with the Commission as a change in a rate schedule. See 13 CFR 35.13.

SEA Rate Schedule No. 2 governs the sale of electricity from a 45 megawatt biomass fired electric generation facility located in the Town of Eustis, Maine (the Project).

The purpose of these filings is to allow for the closing and implementation of a series of transactions that will provide savings to the ratepayers of CMP, to the extent determined by the Maine Public Utilities Commission. SEA Rate Schedule No. 2 will replace an existing high cost wholesale power sales agreement between SEA and Central Maine Power Company (CMP). The effective date of SEA Rate Schedule No. 2, and closing on associated transactions, is subject to final approval by the Maine Public Service Commission. The transactions do not require and will not result in the withdrawal of any capacity from the market.

SEA requests that the Commission expedite public review of the filing, in light of the fact that the Maine Public Utilities Commission is reviewing the actual ratepayer impact of the forgoing transactions in a concurrent docket. The Commission ordinarily allows 60 days after the date of such a filing before final action can be taken.

Comment date: June 15, 1998, in accordance with Standard Paragraph E at the end of this notice.

3. Atlantic City Electric Company, Inc.

[Docket No. ER97–3189–013]

Take notice that on March 27, 1998, Public Service Electric and Gas Company submitted an amendment to the compliance filing it submitted on January 26, 1998 in compliance with Ordering Paragraph (P) and (T) of the Commission's Order in Pennsylvania-New Jersey-Maryland Interconnection, et al., 81 FERC ¶ 61,257 (1997). PSE&G states that this amendment is required to conform the rates in the January 26, 1998, compliance filing with the revised transmission rates filed in response to the Commission's order on clarification in Pennsylvania-New Jersey-Maryland Interconnection, *et al.*, 82 FERC ¶ 61,068 (1998).

Comment date: May 26, 1998, in accordance with Standard Paragraph E at the end of this notice.

4. Central Power and Light Company, West Texas Utilities Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company

[Docket No. ER98–857–000]

Take notice that on May 12, 1998, Central Power and Light Company, West Texas Utilities Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company (collectively, the CSW Operating Companies) gave notice of the withdrawal of their filing in the above captioned proceeding. The CSW Operating Companies state that the Commission's December 10 order issued in Docket No. OA97–24–000 and the submission of a revised open access transmission tariff on February 17, 1998 in response to that order, renders the submission of their filing in this proceeding unnecessary.

The CSW Operating Companies state that a copy of this filing has been served on the Public Utility Commission of Texas, the Louisiana Public Service Commission, the Arkansas Public Service Commission, the Oklahoma Corporation Commission and all parties to this proceeding.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

5. PJM Interconnection, L.L.C.

[Docket No. ER98–1386–000]

Take notice that on April 17, 1998, the PJM Interconnection, L.L.C. (PJM), tendered for filing a letter stating that MidCon and MC2 rescind their request to withdraw from membership in PJM.

Comment date: May 27, 1998, in accordance with Standard Paragraph E at the end of this notice.

6. The Washington Water Power Co.

[Docket No. ER98–2434–000]

Take notice that on May 12, 1998, The Washington Water Power Company (WWP), filed notice of withdrawal of its filing with the Federal Energy Regulatory Commission of a Long-Term Firm Point-To-Point Transmission Service Agreement with Avista Energy, Inc.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

7. Minnesota Power & Light Company

[Docket No. ER98–2628–000]

Take notice that on April 24, 1998, Minnesota Power & Light Company tendered for filing an amendment in the above-referenced docket.

Comment date: May 27, 1998, in accordance with Standard Paragraph E at the end of this notice.

8. Oeste Power Generation, L.L.C.

[Docket No. ER98–2961–000]

Take notice that on May 12, 1998, Oeste Power Generation, L.L.C. (Oeste Power), tendered for filing a service agreement establishing NorAm Energy Services, Inc. (NES), as a customer under Oeste Power's market-based rate sales tariff. Oeste Power requests an effective date of April 13, 1998, for the service agreement.

Oeste Power states that a copy of the filing was served on NES.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

9. Alta Power Generation, L.L.C.

[Docket No. ER98–2962–000]

Take notice that on May 12, 1998, Alta Power Generation, L.L.C. (Alta Power), tendered for filing a service agreement establishing NorAm Energy Services, Inc. (NES), as a customer under Alta Power's market-based rate sales tariff. Alta Power requests an effective date of April 13, 1998, for the service agreement.

Alta Power states that a copy of the filing was served on NES.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

10. Ocean Vista Power Generation, L.L.C.

[Docket No. ER98–2963–000]

Take notice that on May 12, 1998, Ocean Vista Power Generation, L.L.C. (Ocean Vista), tendered for filing a service agreement establishing NorAm Energy Services, Inc. (NES), as a customer under Ocean Vista's market-based rate sales tariff. Ocean Vista requests an effective date of April 13, 1998, for the service agreement.

Ocean Vista states that a copy of the filing was served on NES.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

11. Mountain Vista Power Generation, L.L.C.

[Docket No. ER98–2964–000]

Take notice that on May 12, 1998, Mountain Vista Power Generation, L.L.C. (Mountain Vista), tendered for filing a service agreement establishing NorAm Energy Services, Inc. (NES), as a customer under Mountain Vista's market-based rate sales tariff. Mountain Vista requests an effective date of April 13, 1998 for the service agreement.

Mountain Vista states that a copy of the filing was served on NES.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

12. Consumers Energy Company

[Docket No. ER98–2965–000]

Take notice that on May 12, 1998, Consumers Energy Company (Consumers) tendered for filing an executed Service Agreement for Network Integration Transmission Service pursuant to Consumers' Open Access Transmission Service Tariff and a Network Operating Agreement. Both were with the Cannon-Muskegon Corporation and have effective dates of May 1, 1998.

Copies of the filed agreement were served upon the Michigan Public Service Commission and the customer.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

13. FirstEnergy System

[Docket No. ER98–2966–000]

Take notice that on May 12, 1998, FirstEnergy System filed a Service Agreement to provide Non-Firm Point-to-Point Transmission Service for Merchant Energy Group of the Americas, the Transmission Customer. Services are being provided under the FirstEnergy System Open Access Transmission Tariff submitted for filing by the Federal Energy Regulatory Commission in Docket No. ER97–412–000. The proposed effective date under this Service Agreement is April 27, 1998.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

14. Alliant Service, Inc.

[Docket No. ER98–2967–000]

Take notice that on May 12, 1998, Alliant Services, Inc., tendered for filing an executed Service Agreements for firm and non-firm point-to-point transmission service, establishing Northern States Power Company as a point-to-point Transmission Customer under the terms of the Alliant Services, Inc., transmission tariff.

Alliant Services, Inc., requests an effective date of April 17, 1998, and accordingly, seeks waiver of the Commission's notice requirements. A copy of this filing has been served upon the Public Service Commission of Wisconsin.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

15. Montaup Electric Company

[Docket No. ER98–2968–000]

Take notice that on May 12, 1998, Montaup Electric Company (Montaup), tendered for filing certain revisions to the service agreements between Montaup and its two retail affiliates doing business in Rhode Island, Blackstone Valley Electric Company and Newport Electric Corporation, and between Montaup and its retail affiliate doing business in the Commonwealth of Massachusetts, Eastern Edison Company. Montaup requests that these service agreements be accepted and allowed to be made effective as of June 11, 1998.

According to Montaup, the purpose of its filing is to effectuate a reduction in Montaup's Installed Capability Responsibility as that term is defined in Section 12.2 of the New England Power Pool Tariff on file with the Commission.

Copies of the filing were served upon Montaup's jurisdictional customers and upon affected state agencies.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

16. FirstEnergy System

[Docket No. ER98–2969–000]

Take notice that on May 12, 1998, FirstEnergy System filed Service Agreements to provide Firm Point-to-Point Transmission Service for Merchant Energy Group of the Americas and AYP Energy, Incorporated, the Transmission Customers. Services are being provided under the FirstEnergy System Open Access Transmission Tariff submitted for filing by the Federal Energy Regulatory Commission in Docket No. ER97–412–000. The proposed effective dates under the Service Agreements are April 27, 1998 and May 1, 1998 respectively, for the above mentioned Service Agreements in this filing.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

17. Delmarva Power & Light Company

[Docket No. ER98–2970–000]

Take notice that on May 16, 1998, Delmarva Power & Light Company (Delmarva), tendered for filing executed umbrella service agreements with Continental Energy Services, L.L.C., VTEC Energy, Inc., SCANA Energy Marketing, Inc., and Southern Company Energy Marketing L.P., under Delmarva's market rate sales tariff, FERC Electric Tariff, Original Volume No. 14, that was filed by Delmarva in Docket No. ER96–2571–000. Delmarva requests that the Commission make the agreements effective as of their respective execution dates.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

18. El Segundo Power, LLC

[Docket No. ER98–2971–000]

Take notice that on May 12, 1998, El Segundo Power, LLC, tendered for filing pursuant to Section 205 of the Federal Power Act an amendment to its Electric Rate Schedule FERC No. 1, which would allow El Segundo Power, LLC to sell ancillary services at market-based rates. El Segundo Power, LLC, has requested an effective date of April 15, 1998.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

19. Long Beach Generation LLC

[Docket No. ER98–2972–000]

Take notice that on May 12, 1998, Long Beach Generation LLC tendered for filing pursuant to Section 205 of the Federal Power Act an amendment to its Electric Rate Schedule FERC No. 1, which would allow Long Beach Generation LLC to sell ancillary services at market-based rates. Long Beach Generation LLC has requested an effective date of April 14, 1998.

Comment date: June 1, 1998, in accordance with Standard Paragraph E at the end of this notice.

20. Lyon Rural Electric Cooperative

[Docket No. ES98–32–000]

Take notice that on May 7, 1998, Lyon Rural Electric Cooperative (Lyon), filed an application with the Federal Energy Regulatory Commission, under Section 204 of the Federal Power Act, requesting an order authorizing the issuance of up to $3,500,000] in long-term debt, over a two-year period commencing June 30, 1998. Lyon also requests to be granted a waiver of the Commission's competitive bid or negotiated placement requirement, under 18 CFR 34.2, pursuant to the authorization requested in this docket.

Comment date: June 17, 1998, in accordance with Standard Paragraph E at the end of this notice.

21. Tampa Electric Company

[Docket Nos. OA96–116–002 and ER95–1775–002]

Take notice that on April 20, 1998, Tampa Electric Company tendered for filing corrected tariff sheets for the Settlement Agreement filed on January 20, 1998 in the above-referenced dockets.

Comment date: May 27, 1998, in accordance with Standard Paragraph E at the end of this notice.

22. Westmoreland-LG&E Partners (Roanoke Valley)

[Docket Nos. QF92–180–004, EL98–47–000, Docket Nos. EL94–10–002, QF86–177–003]

Take notice that on May 11, 1998, Westmoreland-LG&E Partners (the Partnership) submitted a Petition for Declaratory Order or, in the Alternative, Request for Waiver of QF Ownership Standard. The Partnership is the owner of a 45.1 MW topping-cycle cogeneration facility that has previously been certified by the Commission as a qualifying cogeneration facility, see Westmoreland-LG&E Partners (Roanoke Valley II), 60 FERC ¶ 62,215 (1992); Westmoreland-LG&E Partners (Roanoke Valley II), 64 FERC ¶ 62,215 (1993).

Comment date: June 15, 1998, in accordance with Standard Paragraph E at the end of this notice.

Standard Paragraph

E. Any person desiring to be heard or to protest said filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 18 CFR 385.214). All such motions or protests should be filed on or before the comment date. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a motion to intervene. Copies of these filings are on file with the Commission and are available for public inspection.

David P. Boergers,

Acting Secretary.

[FR Doc. 98–13559 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2232–331]

Duke Energy Corporation; Notice of Availability of Environmental Assessment

May 15, 1998.

An Environmental Assessment (EA) is available for public review. The EA was prepared for an application filed by the Duke Energy Corporation, licensee for the Catawba-Wateree Hydroelectric Project. In its application filed on August 9, 1996, the licensee requests permission to grant an easement of project property to Overlook Properties to construct one boat ramp and 180 floating boat slips at 10 locations. The proposed facilities would provide access for residents of Overlook Subdivision to Mountain Island Lake near Charlotte in Mecklenberg County, North Carolina. On May 29, 1997, the licensee filed a supplement to permit Overlook Properties, Inc. to dredge a 0.86-acre area to improve water depth for boating access.

The EA finds that the proposed action would not be a major federal action significantly affecting the quality of the human environment.

The EA was written by staff in the Office of Hydropower Licensing, Federal Energy Regulatory Commission. Copies of the EA can be obtained by calling the Commission's public reference room at (202) 208–1371.

Linwood A. Watson, Jr.,

Acting Secretary.

[FR Doc. 98–13483 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Transfer of License

May 15, 1998.

Take notice that the following hydroelectric application has been filed with the Commission and is available for public inspection:

a. *Type of Application:* Transfer of License.

b. *Project No.:* 2233–034.

c. *Date Filed:* April 13, 1998.

d. *Applicants:* Simpson Paper Company (Simpson), Portland General Electric Company (PGE), and Smurfit Newsprint Corporation (Smurfit).

e. *Name of Project:* Willamette Falls Hydroelectric Project.

f. *Location:* On the Willamete River in Clackamas County, Oregon.

g. *Filed Pursuant to:* Federal Power Act, 16 USC §§ 791(a)-825(r).

h. *Contacts:* Jeanne Verville, Simpson Paper Company, 1201 Third Avenue, Suite 4900, Seattle, WA 98101–3045, (206) 224–5000. Gary Hackett, Portland General Electric Company, 121 S.W. Salmon, Portland, OR 97204, (503) 464–8005. Jerry Stanley, Smurfit Newsprint Corporation, 427 Main Street, Oregon City, OR 97045, (503 650–4529.

i. *FERC Contact:* Mr. Lynn R. Miles, (202) 219–2671.

j. *Comment Date:* June 29, 1998.

k. *Description of the Application:* Simpson, the licensee for Willamette Falls Hydroelectric Project, jointly and severally with PGE and Smurfit, requests Commission approval to transfer the project license to PGE and Smurfit.

l. This notice also consists of the following standard paragraphs: B, C1, and D2.

B. Comments, Protests, or Motions to Intervene—Anyone may submit comments, a protest, or a motion to intervene in accordance with the requirements of Rules of Practice and Procedure, 18 CFR 385.210, .211, .214. In determining the appropriate action to take, the Commission will consider all protests or other comments filed, but

only those who file a motion to intervene in accordance with the Commission's Rules may become a party to the proceeding. Any comments, protests, or motions to intervene must be received on or before the specified comment date for the particular application.

C1. 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. 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, N.E., Washington, D.C. 20426. A copy of any motion to intervene must also be served upon each representative of the Applicant specified in the particular application.

D2. Agency Comments—Federal, state, and local agencies are invited to file comments on the described application. A copy of the application may be obtained by agencies directly from the Applicant. If an agency does not file comments within the time specified for filing comments, it will be presumed to have no comments. One copy of an agency's comments must also be sent to the Applicant's representatives.

Linwood A. Watson, Jr,.

Acting Secretary.

[FR Doc. 98–13484 Filed 5–20–98; 8:45 am]

BILLING CODE 6717–01–M

ENVIRONMENTAL PROTECTION AGENCY

[FRL–6100–3]

Agency Information Collection Activities: Proposed Collection; Comment Request; Source Compliance and State Action Reporting/Compliance Reporting to the Aerometric Information and Retrieval System (AIRS)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this document announces that EPA is planning to submit the following continuing Information Collection Request (ICR) to the Office of Management and Budget (OMB): Source Compliance and State Action Reporting, EPA ICR Number 0107, OMB control number 2060–0096, current expiration date 7/31/98. Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on specific aspects of the proposed information collection as described below.

DATES: Comments must be submitted on or before July 21, 1998.

ADDRESSES: US EPA Office of Compliance, 401 M Street, Washington DC Copies of background materials may be obtained without charge from Mark Antell (2222A) at this address, or electronically, via EMAIL request to antell.mark@epamail.epa.gov.

FOR FURTHER INFORMATION CONTACT: Mark Antell, 202/564–5003, FAX 202/564-0032, EMAIL antell.mark@epamail.epa.gov.

SUPPLEMENTARY INFORMATION:

Affected entities: Entities potentially affected by this action are State, District, Commonwealth and territorial governments.

Title: Source Compliance and State Action Reporting, OMB Control Number 2060–0096, EPA ICR No. 0107 expiring July 31, 1998.

Abstract: Source Compliance and State Action reporting is an activity whereby State, District, Commonwealth and territorial (hereafter referred to as State) governments make air compliance information available to EPA on a quarterly basis via input to the Aerometric Information and Retrieval System (AIRS). The information provided to EPA includes compliance determinations and compliance activities. EPA uses this information to assess progress toward meeting emission requirements developed under the authority of the Clean Air Act to protect and maintain the atmospheric environment and the public health. The compliance information in AIRS is used by many States and by all ten EPA Regional offices on a frequent basis for managing activities of their air pollution control programs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR Chapter 15.

The EPA would like to solicit comments to:

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

(ii) Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

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

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

Burden Statement:

The burden for this effort was reduced dramatically in the mid 90's from 145633 hours/yr (pre-1995 ICR inventory), to the current approved 58686 hours. The burden change was due to reduced reporting requirements and improved technology. This request reflects modest but continuing burden reductions for similar reasons.

Number of respondents—55 (State governments).

Number of hours required per response—52 to 405 depending on State size.

Number of responses required per respondent per year—4.

Total hours/cost requested—55,500/$1.47 million.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Dated: May 14, 1998.

Elaine Stanley,

Director, Office of Compliance.

[FR Doc. 98–13607 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[OPPTS–00237; FRL–5781–4]

Toxic Chemicals; Asbestos and PCBs; Agency Information Collection Activities

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this notice announces that EPA is planning to submit the following Information Collection Requests (ICRs) to the Office of Management and Budget (OMB). Before submitting the ICRs to OMB for review and approval, EPA is soliciting comments on specific aspects of the information collections described below. The ICRs are: (1) a continuing ICR entitled ''Reporting and Recordkeeping Requirements for Asbestos Abatement Worker Protection,'' EPA ICR No. 1246.06, OMB No. 2070-0072, which relates to reporting requirements found at 40 CFR part 763, subpart G, and (2) a continuing ICR entitled ''PCB Notification and Manifesting of PCB Waste Activities, and Records of PCB Storage and Disposal,'' EPA ICR No. 1446.06, OMB No. 2070-0112, which relates to reporting requirements found at 40 CFR part 761. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9.

DATES: Written comments must be submitted on or before July 20, 1998.

ADDRESSES: Each comment must bear the respective docket control number and administrative record numbers, as follows: comments on ICR No. 1246.06 should reference docket control number ''OPPTS–00237'' and administrative record number 192; comments on ICR No. 1446.06 should reference docket control number ''OPPTS–00237'' and administrative record number 193. All comments should be sent in triplicate to: OPPT Document Control Officer (7407), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 401 M St., SW., Rm. G099, Washington, DC 20460. Comments and data may also be submitted electronically to: oppt.ncic@epamail.epa.gov. Follow the instructions under Unit III. of this document. No TSCA Confidential Business Information (CBI) should be submitted through e-mail.

All comments that contain information claimed as CBI must be clearly marked as such. Three sanitized copies of any comments containing information claimed as CBI must also be submitted and will be placed in the public record for this document. Persons submitting information any portion of which they believe is entitled to treatment as CBI by EPA must assert a business confidentiality claim in accordance with 40 CFR 2.203(b) for each such portion. This claim must be made at the time that the information is submitted to EPA. If a submitter does not assert a confidentiality claim at the time of submission, EPA will consider this as a waiver of any confidentiality claim and the information may be made available to the public by EPA without further notice to the submitter.

FOR FURTHER INFORMATION CONTACT: For general information contact: Susan B. Hazen, Director, Environmental Assistance Division (7408), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 401 M St., SW., Washington, DC 20460, Telephone: 202–554–1404, TDD: 202–554–0551, e-mail: TSCA-Hotline@epamail.epa.gov. For technical information contact: Tony Baney, National Program Chemicals Division (7404), Office of Pollution Prevention and Toxics, Environmental Protection Agency, 401 M St., SW., Washington, DC 20460, Telephone: 202–260–3933; Fax: 202–260–1724; e-mail: baney.tony@epamail.epa.gov.

SUPPLEMENTARY INFORMATION:

Electronic Availability:

Internet

Electronic copies of the ICRs are available from the EPA Home Page at the Federal Register - Environmental Documents entry for this document under ''Laws and Regulations'' (http://www.epa.gov/fedrgstr/).

Fax-on-Demand

Use a faxphone to call 202-401-0527 and select item 4059 for a copy of ICR No. 1246.06, or select item 4060 for a copy of ICR No. 1446.06.

I. Background

Affected entities: Entities potentially affected by this action are: with respect to ICR No. 1246.06, state and local governments without OSHA-approved state plans that have employees engaged in asbestos abatement; and, with respect to ICR No. 1446.06, persons who own or operate equipment containing polychlorinated biphenyls (PCBs) or who own or operate PCB storage and disposal facilities. For each collection of information addressed in this notice, EPA would like to solicit comments to:

1. Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility.
2. Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used.
3. Enhance the quality, utility, and clarity of the information to be collected.
4. 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.

II. Information Collections

EPA is seeking comments on the following two ICRs, as well as the Agency's intention to renew the corresponding OMB approvals.

Title: Reporting and Recordkeeping Requirements for Asbestos Abatement Worker Protection.

ICR numbers: EPA ICR No. 1246.06, OMB No. 2070–0072.

Approval expiration date: August 31, 1998.

Abstract: EPA's asbestos worker protection rule (40 CFR 763, subpart G) is designed to provide occupational exposure protection to state and local government employees who are engaged in asbestos abatement activities in states that do not have state plans approved by the Occupational Safety and Health Administration (OSHA). The rule provides protection for public employees not covered by the OSHA standard from the adverse health effects associated with occupational exposure to asbestos.

This rule requires state and local governments to monitor employee exposure to asbestos, take action to reduce exposure, to monitor employee health, train employees about asbestos hazards, and provide employees with information about exposures to asbestos and the associated health effects. The rule also requires state and local governments to notify EPA before commencing any asbestos abatement project. State and local governments must maintain medical surveillance and monitoring records and training records on their employees, must establish a set of written procedures for respirator programs, and must maintain procedures and records of respirator fit tests. EPA will use the information to

monitor compliance with the asbestos worker protection rule.

Responses to the collection of information are mandatory (see 40 CFR part 763, subpart G). Respondents may claim all or part of a notice confidential. EPA will disclose information that is covered by a claim of confidentiality only to the extent permitted by, and in accordance with, the procedures in TSCA section 14 and 40 CFR part 2.

Burden statement: The burden to respondents for complying with this ICR is estimated to total 47,133 hours at a cost of $2,394,000. These totals are based on an average burden of approximately 22.7 hours per response for an estimated 2,080 respondents making one or more responses annually. These estimates include the time needed to review instructions; develop, acquire, install and utilize technology and systems for the purposes of collecting, validating and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Title: PCB Notification and Manifesting of PCB Waste Activities, and Records of PCB Storage and Disposal.

ICR numbers: EPA ICR No. 1446.06, OMB No. 2070-0112.

Approval expiration date: September 30, 1998.

Abstract: Section 6(e) of the Toxic Substances Control Act (TSCA) directs EPA to regulate the marking, disposal, manufacturing, processing, distribution in commerce, and use of PCBs. EPA has promulgated rules prescribing methods for disposal of PCBs and criteria for the storage and handling of PCBs prior to disposal. These regulations require persons who own or operate equipment containing PCBs, or persons who own and operate facilities that store or dispose of PCB waste, to maintain records and submit certain reports, including third-party notifications, on the handling and disposition of such PCBs and PCB Items. This ICR addresses the burden associated with such recordkeeping and reporting requirements.

Responses to the collection of information are mandatory (see 40 CFR part 761). Respondents may claim all or part of a notice confidential. EPA will disclose information that is covered by a claim of confidentiality only to the extent permitted by, and in accordance with, the procedures in TSCA section 14 and 40 CFR part 2.

Burden statement: The burden to respondents for complying with this ICR is estimated to total 175,453 hours per year with an annual cost of $7,337,200. These totals are based on an average burden ranging between approximately 1 hour and 428 hours per response, depending upon the category of respondent, for an estimated 50,955 respondents making one or more responses annually. These estimates include the time needed to review instructions; develop, acquire, install and utilize technology and systems for the purposes of collecting, validating and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

III. Public Record and Electronic Submissions

The official record for this document, as well as the public version, has been established for this document under docket number ''OPPTS-00237'' (including comments and data submitted electronically as described below). A public version of this record, including printed, paper versions of electronic comments, which does not include any information claimed as CBI, is available for inspection from 12 noon to 4 p.m., Monday through Friday, excluding legal holidays. The official record is located in the TSCA Nonconfidential Information Center, Rm. NE-B607, 401 M St., SW., Washington, DC 20460.

Electronic comments can be sent directly to EPA at:

oppt.ncic@epamail.epa.gov

Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. Comments and data will also be accepted on disks in WordPerfect 5.1/6.1 or ASCII file format. All comments and data in electronic form addressing ICR No. 1246.06 must be identified by docket control number ''OPPTS-00237'' and administrative record number 192. All comments and data in electronic form addressing ICR No. 1446.06 must be identified by docket control number ''OPPTS-00237'' and administrative record number 193. Electronic comments on this document may be filed online at many Federal Depository Libraries.

List of Subjects

Environmental protection, Information collection requests, Reporting and recordkeeping.

Dated: May 13, 1998.

Lynn R. Goldman,

Assistant Administrator for Prevention, Pesticides and Toxic Substances.

[FR Doc. 98–13629 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–F

ENVIRONMENTAL PROTECTION AGENCY

Agency Information Collection Activities: Submission for OMB Review; Comment Request; Graphic Arts Industry Subject to New Source Performance Standards

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this notice announces that the following Information Collection Request (ICR) has been forwarded to the Office of Management and Budget (OMB) for review and approval: New Source Performance Standards for the Graphic Arts Industry, OMB Control Number 2060–0105, expiration date 7/31/98. The ICR describes the nature of the information collection and its expected burden and cost; where appropriate, it includes the actual data collection instrument.

DATES: Comments must be submitted on or before June 22, 1998.

FOR FURTHER INFORMATION CONTACT: For a copy of the ICR, call Sandy Farmer at EPA, by phone at (202) 260–2740, by E-Mail at Farmer.Sandy@epamail.epa.gov or download off the Internet at http://www.epa.gov/icr/icr.htm, and refer to EPA ICR No. 0657.06

SUPPLEMENTARY INFORMATION:

Title: NSPS for Graphic Arts Industry (OMB Control No. 2060–0105, expiration date 7/31/98; EPA ICR No. 0657.06). This is a request for extension of a currently approved collection.

Abstract: The EPA is charged under Section 111 of the Clean Air Act, as amended, to establish standards of performance for new stationary sources that reflect:

* * * application of the best technological system of continuous emissions reduction which (taking into consideration the cost * * * and energy requirements) the Administrator determines has been

adequately demonstrated [Section 111 (a)(1)].

In addition, Section 114 (a) requires that any owner or operator subject to any Subpart to establish and maintain records, make reports, install, use and maintain monitoring equipment or methods as required, and provide other information as EPA may deem necessary.

The New Source Performance Standards (NSPS) for subpart QQ were proposed on October 28, 1980, and promulgated on November 8, 1982. These standards apply to the following facilities in NSPS Subpart QQ: each publication rotogravure printing press (not including proof presses) commencing construction, modification or reconstruction after the date of proposal. This information is being collected to assure compliance with 40 CFR Part 60, subpart QQ.

Owners or operators of the affected facilities described have certain notification, reporting, and record keeping requirements under this rule. One example of each is: a one-time-only notification of the date of the anticipated and actual dates of startup, keep records of monthly emissions calculations, and a report of the initial performance test. Any owner or operator subject to the provisions of this part shall maintain a file of these measurements, and retain the file for at least two years following the date of such reports and records.

Approximately 21 facilities are currently subject to the standard, and it is estimated that an additional 3 facilities will become subject to the standard in the next three years. It is further assumed that less than half of the existing facilities will be adding or modifying a press during the three year period. Therefore, there are 189 existing presses subject to this standard and an additional 10 affected units will be added each year. This is based upon the AIRS Facility Subsystem Report. All reports are sent to the delegated State or Local Authority. In the event that there is no such delegated authority, the reports are sent directly to the EPA Regional Office. Information is entered into the AIRS database.

The information requested as part of this rule includes one-time-only notifications; records about the initial performance test, changes in the operation of the facility, and the exceeding of parameters; and semi-annual reports of the exceeded results.

Notifications are used to inform the agency or delegated authority when a source becomes subject to the standard. The reviewing authority may then inspect the source to check if the pollution control devices are properly installed and operated and the standard is being met. Performance test reports are needed as these are the Agency's record of a source's initial capability to comply with the emission standard.

An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15. The **Federal Register** Notice required under 5 CFR 1320.8(d), soliciting comments on this collection of information was published on 12/02/97 (62 FR 63703). No comments were received.

Burden Statement: The annual public reporting and record keeping burden for this collection of information is estimated to average 60 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency.

Respondents/Affected entities: Owners/Operators of publication Rotogravure printing presses.

Estimated Number of Respondents: 24.

Frequency of Response: On occasion, Semi-Annually.

Estimated total Annual Hour Burden: 2988.

Estimated Total Annualized Cost Burden: 0.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the following addresses. Please refer to EPA ICR No. 0657.06 and OMB Control No. 2060–0105 in any correspondence.

Ms. Sandy Farmer, U.S. Environmental Protection Agency, OPPE Regulatory Information Division (2137), 401 M Street, SW, Washington, DC 20460

and

Office of Information and Regulatory Affairs, Office of Management and Budget, Attention: Desk Officer for EPA 725 17th Street, NW, Washington, DC 20503.

Dated: May 18, 1998.

Richard T. Westlund,

Acting Director, Regulatory Information Division.

[FR Doc. 98–13611 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–6101–3]

Agency Information Collection Activities: Submission for OMB Review; Comment Request; National Pollutant Discharge Elimination System for the Water Quality Guidance for the Great Lakes System

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this notice announces that the following Information Collection Request (ICR) has been forwarded to the Office of Management and Budget (OMB) for review and approval: National Pollutant Discharge Elimination System Great Lakes Water Quality Guidance (EPA ICR Number 1639.03; OMB Control Number 2040–0180; expiration date June 30, 1998). The ICR describes the nature of the information collection and its expected burden and cost; where appropriate, it includes the actual data collection instrument.

DATES: Comments must be submitted on or before June 22, 1998.

FOR FURTHER INFORMATION CONTACT: Contact Sandy Farmer at EPA by phone at (202) 260–2740, by e-mail at farmer.sandy@epamail.epa.gov, or download off the Internet at http://www.epa.gov/icr and refer to EPA ICR No. 1639.03.

SUPPLEMENTARY INFORMATION:

Title: National Pollutant Discharge Elimination System Great Lakes Water Quality Guidance (OMB Control No. 2040–0180; EPA ICR No.1639.03) expiring June 30, 1998. This is a request for extension of a currently approved collection.

Abstract: Section 101 of the Great Lakes Critical Programs Act (CPA) amends Section 118 of the Clean Water Act (CWA) and directs EPA to publish water quality guidance for the Great Lakes System. Provisions of the Guidance are codified in 40 CFR Part 132. The Guidance establishes minimum water quality criteria, implementation procedures, and antidegradation provisions for the Great Lakes System.

Permitting authorities currently require dischargers to provide information such as the name, location, and description of facilities to identify the facilities that require permits. EPA and authorized NPDES States store much of this basic information in the

Permit Compliance System (PCS) database. PCS provides EPA with a nationwide inventory of NPDES permit holders. EPA Headquarters uses the information contained in the PCS to develop reports on permit issuance, backlogs, and compliance rates. The Agency also uses the information to respond to public and Congressional inquiries, develop and guide its policies, formulate its budgets, assist States in acquiring authority for permitting programs, and manage its programs to ensure national consistency in permitting.

NPDES permit applications and requests for supplemental information currently require information about wastewater treatment systems, pollutants, discharge rates and volumes, whole effluent toxicity testing and other data. Additional information collection requirements that may be necessary to implement State, Tribal, or EPA promulgated provisions consistent with the final Guidance include: (1) Monitoring (pollutant-specific and whole effluent toxicity or WET); (2) pollutant minimization programs; (3) bioassays to support the development of water quality criteria; (4) antidegradation policy/demonstrations; and (5) regulatory relief options (e.g., variances from water quality criteria).

This information may be used to ensure compliance with provisions consistent with the Guidance and re-evaluate existing permit conditions and monitoring requirements. Data on discharges is entered into STORET and PCS, EPA's databases for ambient water quality data and NPDES permits, respectively. Results of water quality criteria testing will be entered into an EPA Information Clearinghouse database.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR Part 9 and 48 CFR Chapter 15. The **Federal Register** Notice required under 5 CFR 1320.8(d), soliciting comments on this collection of information was published on December 29, 1997, (62 FR 67637–67639); no comments were received.

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 18.8 hours per response. The burden will vary among dischargers and states and, depending on effluent quality, according to the requirements of the Guidance provisions. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Respondents/Affected Entities: Industries and local governments, as POTWs, discharging toxic pollutants to waters in the Great Lakes System as defined in 40 CFR 132.2; the governments of the eight Great Lakes States (Illinois, Indiana, Michigan, Minnesota, New York, Ohio, Pennsylvania, Wisconsin).

Estimated Number of Respondents: 588 major industrial and POTW dischargers, and 3,207 minor dischargers.

Frequency of Response: varies depending on dischargers effluent characteristics.

Estimated Total Annual Hour Burden: 43,395 hours.

Estimated Total Annualized Cost Burden: $2,504,000.

Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the following addresses. Please refer to EPA ICR No. 1639.03 and OMB Control No. 2040–0180 in any correspondence to: Ms. Sandy Farmer, U.S. Environmental Protection Agency, OPPE Regulatory Information Division (2137), 401 M Street, SW, Washington, DC 20460; and, Office of Information and Regulatory Affairs, Office of Management and Budget, Attention: Desk Officer for EPA, 725 17th Street, NW, Washington, DC 20503.

Dated: May 15, 1998.

Richard Westlund,

Acting Director, Regulatory Information Division.

[FR Doc. 98–13612 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–U

ENVIRONMENTAL PROTECTION AGENCY

[FRL–5990–3]

Delegation of National Emission Standards for Hazardous Air Pollutants; Pennsylvania

AGENCY: Environmental Protection Agency (EPA).

ACTION: Information notice.

SUMMARY: The purpose of this notice is to announce that on January 5, 1998, EPA granted the Commonwealth of Pennsylvania's request for partial delegation of the National Emission Standards for Hazardous Air Pollutants (NESHAPs), and associated infrastructure programs. This request for partial delegation of authority only pertains to affected sources of hazardous air pollutants (HAPs), for all source categories which are located at major sources. EPA granted the delegation with certain restrictions. The restrictions involve EPA's retainment of certain authorities including: implementation and enforcement of standards that control radionuclides or that apply to an area source which is not located at a major source, implementation and enforcement of an accidental release program, approvals of alternative means of limiting emissions, alternative control technologies, alternative test methods, alternative monitoring methods; and the authority to make certain applicability determinations. In addition, certain provisions will be delegated only on a case-by-case basis and require notification by the Pennsylvania Department of Environmental Protection (PADEP) to EPA. These provisions include: approvals of compliance extensions, site-specific test plans, performance evaluation plans; approvals of minor alternatives to test methods, monitoring, and shorter sampling times/volumes; and waivers of performance testing and record keeping.

EFFECTIVE DATES: The effective date of the delegation authority is January 5, 1998.

ADDRESSES: Copies of the requests for delegation of authority and EPA's letters of delegation are available for public inspection at EPA's Region III Office, 841 Chestnut Bldg., Philadelphia, PA 19107; PADEP's Central Office, the PADEP regional offices, the Allegheny County Bureau of Air Pollution Control office and the Philadelphia Air Management Services office during normal business hours. The addresses of these offices are provided below. Effective immediately, all notifications,

requests, applications, reports and other correspondence required pursuant to 40 CFR part 63 for major sources, as defined in 40 CFR part 70, to be sent to the Administrator should be submitted to EPA Region III office and, with respect to sources located in listed counties, to the following addresses. Although, by this delegation, PADEP is the sole agency authorized to implement and enforce the 40 CFR part 63 standards, Allegheny County Bureau of Air Pollution Control and Philadelphia Air Management Services will serve as agents to PADEP for the receipt of all notifications, requests, applications, reports and other correspondence required pursuant to 40 CFR part 63 for major sources, as defined in 40 CFR part 70 for Allegheny County and Philadelphia County, respectively. Allegheny County Bureau of Air Pollution Control and Philadelphia Air Management Services will notify PADEP's Central Office of the receipt of this information for proper implementation and enforcement.

PADEP Central Office—Rachel Carson State Office Building, 400 Market Street, 12th Floor, Harrisburg, PA 17105–8468, Telephone: 717–787–9702, Contact: Permit Chief

PADEP Region I-Southeast Regional Office, Lee Park—Suite 6010, 555 North Lane, Conshohocken, PA 19428, Telephone: 610–832–6242,Contact: Program Manager Counties: Bucks, Chester, Delaware, Montgomery

PADEP Region II-Northeast Regional Office, Two Public Square, Wilkes-Barre, PA 18711–0790, Telephone: 717–826–253, Contact: Program Manager, Counties: Carbon, Lackawanna, Lehigh, Luzerne, Monroe, Northampton, Pike, Schuylkill, Susquehanna, Wayne, Wyoming

PADEP Region III–Southcentral Regional Office, One Ararat Boulevard, Harrisburg, PA 17110, Telephone: 717–657–4587, Contact: Program Manager, Counties: Adams, Bedford, Berks, Blair, Cumberland, Dauphin, Franklin, Fulton, Huntingdon, Juniata, Lancaster, Lebanon, Mifflin, Perry, York

PADEP Region IV-Northcentral Regional Office, 208 West 3rd Street, Suite 101, Williamsport, PA 17701, Telephone: 717–327–3637, Contact: Program Manager Counties: Bradford, Cameron, Centre, Clearfield, Clinton, Columbia, Lycoming, Montour, Northumberland, Potter, Snyder, Sullivan, Tioga, Union

PADEP Region V-Southwest Regional Office, 400 Waterfront Drive, Pittsburgh, PA 15222–4745, Telephone 412–442–4174, Contact: Program Manager, Counties: Armstrong, Beaver, Cambria, Fayette, Greene, Indiana, Somerset, Washington, Westmoreland

PADEP Region VI-Northwest Regional Office, 230 Chestnut Street, Meadville, PA 16335–3481, Telephone 814–332–6940, Contact: Program Manager, Counties: Butler, Clarion, Crawford, Elk, Erie, Forest, Jefferson, Lawrence, McKean, Mercer, Venango, Warren

Allegheny County—Allegheny County Health Department, Plan Review Section, Bureau of Air Pollution Control, 301 39th Street, Pittsburgh, PA 15201, Telephone 412–578–8111

Philadelphia County—Department of Public Health, Air Management Services, 321 University Avenue, Spelman Building, Philadelphia, PA 19104, Telephone 215–823–7584

FOR FURTHER INFORMATION CONTACT: Dianne J. Walker, Permit and Technical Assessment Section (3AP11), Air Protection Division, EPA Region III, 841 Chestnut Street, Philadelphia, PA 19107, Telephone: 215–566–3297.

SUPPLEMENTARY INFORMATION: Section 112(l) of the Clean Air Act, as amended November 15, 1990, and 40 CFR part 63, subpart E, authorizes EPA to delegate authority to any state agency which submits adequate regulatory procedures for implementation and enforcement of emission standards of hazardous air pollutants.

On February 13, 1996, the Pennsylvania Department of Environmental Protection (PADEP) requested partial delegation of authority to implement and enforce the National Emission Standards for Hazardous Air Pollutants (NESHAPs) and associated infrastructure programs, pursuant to section 112 of the Clean Air Act (CAA), as set forth in 40 CFR part 63. This request was made in the CAA Title V Operating Permits Program Implementation Agreement which was negotiated between PADEP and EPA. This request for partial delegation of authority only pertains to affected sources of hazardous air pollutants (HAPs), as defined in 40 CFR part 63, for all source categories which are located at major sources, as defined in 40 CFR part 70.

On July 30, 1996, EPA approved PADEP's Title V Operating Permits Program. Requirements for approval, specified in 40 CFR 70.4(b), encompass CAA section 112(l)(5) requirements for approval of a program for delegation of CAA section 112 standards as promulgated by EPA as they apply to 40 CFR part 70 sources. Section 112(l)(5) requires that the State's program contain adequate authorities, adequate resources for implementation and an expeditious compliance schedule for enforcing standards, which are also requirements under 40 CFR part 70. Therefore, as part of the Title V Operating Permits Program approval, EPA also promulgated full approval under CAA section 112(l)(5) and 40 CFR 63.91 of the State's program for receiving delegation of the CAA section 112 standards that are unchanged from Federal standards as promulgated in 40 CFR part 63. This program for delegation only applies to sources covered by the 40 CFR part 70 program.

On January 5, 1998, the Environmental Protection Agency granted the request for partial delegation with certain restrictions. The following authorities will be retained by EPA Region III: (1) implementation and enforcement of standards that control radionuclides (40 CFR 63.12(b)(1)); (2) implementation and enforcement of standards that apply to an area source, as defined in 40 CFR 63.2, which is not located at a major source, as defined in 40 CFR part 70; (3) implementation and enforcement of an accidental release program, as defined in CAA section 112(r) and 40 CFR part 68; (4) approval of alternative means of emission limitations and alternative control technologies; (5) approval of alternative test methods; (6) approval of alternative monitoring methods; and, (7) the authority to make certain applicability determinations, as required by formal requests from owners or operators of facilities or the public. In addition, certain provisions of 40 CFR part 63 are delegated on a case-by-case basis to PADEP and require PADEP to notify U.S. EPA Region III, in writing. These provisions include: (1) compliance extensions; (2) approval of site-specific test and performance evaluation plans; (3) approval of minor alternatives to test methods and monitoring; (4) approval of shorter sampling times/volumes; (5) waiver of performance testing and, (6) waiver of record keeping. As of January 5, 1998, PADEP has primary authority to enforce the standards in 40 CFR part 63 for CAA part 70 sources, however, EPA will retain independent enforcement authority. Pennsylvania has adopted by reference all existing NESHAPs and the corresponding amendments and revisions into 25 Code 127.35. Because PADEP will automatically incorporate by reference all future 40 CFR part 63 NESHAPs and all future amendments and revisions into 25 Code 127.35, this delegation will be automatic (i.e.,

delegation is granted upon Federal promulgation of a standard, amendment or revision).

If the Administrator determines that Pennsylvania cannot adequately implement or enforce the requirements of 40 CFR part 63, this delegation may be revoked in whole or in part.

EPA hereby notifies the public that it has partially delegated the authority for implementation and enforcement of the NESHAPs, pursuant to 40 CFR part 63, as outlined above, to the Pennsylvania Department of Environmental Protection.

The Office of Management and Budget has exempted this action informing the public of partial delegation of NESHAPS to PADEP, as outlined above, from Executive Order 12688 review. This notice is issued under the authority of sections 101, 110, 112 and 301 of the Clean Air Act, as amended (42 U.S.C. 7401, 7410, 7412, 7601).

Dated: March 18, 1998.

Thomas Voltaggio,

Acting Regional Administrator, EPA Region III.

[FR Doc. 98–13618 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–6100–1]

Interim Policy for Addressing Public Health and Welfare Impacts Caused by Wildland and Prescribed Fires in the Nation's Wildlands

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of availability.

SUMMARY: Notice is hereby given that the EPA has issued an ''Interim Air Quality Policy on Wildland and Prescribed Fires.'' The policy addresses public health and welfare impacts caused by wildland and prescribed fires in the Nation's wildlands (areas with little development, such as forests and grasslands). The policy applies to all wildland and prescribed fires managed to achieve resource benefits on public, Indian and privately owned wildlands, regardless of the cause of ignition (e.g., lightning, land management decision, accidental, etc.) or purpose of the fire (e.g., resource management, hazard reduction, etc.). The policy does not apply to other open burning activities, such as burning at residential, commercial or industrial sites; open burning of land-clearing waste or construction debris. It also does not apply to open burning of agricultural waste, crop residue or land in the U.S. Department of Agriculture (USDA) Conservation Reserve Program.

This is an interim policy for two reasons. First, EPA expects recommendations from the USDA based on input from USDA's Air Quality Task Force on how to address public health and welfare impacts caused by agricultural burning. Those recommendations may affect the Agency's understanding of fires in the wildlands versus agricultural fires. Second, until the final rules for implementing EPA's regional haze program are promulgated, it is not possible to formulate final policy with respect to the impact of wildland and prescribed fires on regional haze.

The policy was issued in response to plans by some Federal, tribal and State wildland owners/managers to significantly increase the use of wildland and prescribed fires to achieve resource benefits. The absence of fire effects, due to past management practices, has allowed plant species (e.g., trees and shrubs) that would normally be eliminated by fires to proliferate, vegetation to become dense and insect infestations to go unchecked. In response, wildland owners/managers plan to significantly increase their use of fires to correct these unhealthy conditions and to reduce the risk of wildfires to public and fire fighter safety. The policy integrates two public policy goals: (1) to allow fire to function, as nearly as possible, in its natural role in maintaining healthy wildland ecosystems; and (2) to protect public health and welfare by mitigating the impacts of air pollutant emissions on air quality and visibility.

FOR FURTHER INFORMATION CONTACT: For specific questions on the policy, contact Mr. Kenneth Woodard, U.S. EPA, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–5697, or Mr. Gary Blais, U.S. EPA, MD–15, Research Triangle Park, NC 27711, telephone (919) 541–3223.

SUPPLEMENTARY INFORMATION: The EPA does not directly regulate the use of fire within a State or on Indian lands. The EPA's authority is to enforce the Clean Air Act requirements to attain and maintain the national ambient air quality standards (NAAQS) adopted to protect public health and welfare. This policy recommends that States/tribes implement smoke management programs (SMP's) to mitigate the public health and welfare impacts of fires managed for resource benefits. The goals of SMP's are to mitigate the nuisance and public safety hazards (e.g., on roadways and at airports, etc.) posed by smoke intrusions into populated areas; to prevent deterioration of air quality and NAAQS violations; and to address visibility impacts in mandatory Class I Federal areas. The SMP's establish procedures and requirements for minimizing air pollutant emissions and managing smoke dispersion.

Electronic Availability

A World Wide Web site has been developed for policy and guidance issued by the Office of Air and Radiation. The Uniform Resource Location for the home page of the web site is *http://www.epa.gov/ttn/oarpg.* For assistance, the TTN Helpline is (919) 541–5384. For those persons without electronic capability, a copy may be obtained from Ms. Virginia Wyatt, MD–15, Air Quality Strategies and Standards Division, RTP NC 27711, telephone (919) 541–5628.

Dated: May 15, 1998.

Jeffrey S. Clark,

Acting Director, Office of Air Quality Planning and Standards.

[FR Doc. 98–13616 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–6100–4]

Public Water System Supervision Program Revision for the State of Ohio

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: Public notice is hereby given in accordance with the provision of section 1413 of the Safe Drinking Water Act, as amended, 42 U.S.C. 300f *et seq.*, and 40 CFR part 142, subpart B, the National Primary Drinking Water Regulations (NPDWR), that the State of Ohio is revising its approved Public Water System Supervision (PWSS) primacy program. The Ohio Environmental Protection Agency (OEPA) has adopted new analytical methods, withdrawn outdated analytical methods, and updated older analytical methods for regulated drinking water contaminants. The OEPA has also removed legally obsolete or redundant rules from its regulations, and has adopted technical amendments to correct typographical errors and clarify regulatory language. These regulations correspond to the NPDWRs promulgated by the U.S. Environmental Protection Agency (U.S. EPA) on June 30, 1994, (59 FR 33860–33864); on July 1, 1994, (59 FR 34320–34325); on June 29, 1995, (60

FR 33926–33932); and, on December 5, 1994, (59 FR 62456–62471), as amended on June 29, 1995, (60 FR 34084–34086). The U.S. EPA has completed its review of Ohio's PWSS primacy program revision.

The U.S. EPA has determined that the Ohio rule revision meets the requirements of the Federal rule. Therefore, the U.S. EPA is proposing to approve the OEPA's rule revision.

All interested parties are invited to submit written comments on these proposed determinations, and may request a public hearing on or before June 22, 1998. If a public hearing is requested and granted, the corresponding determination shall not become effective until such time following the hearing, at which the Regional Administrator issues an order affirming or rescinding this action. Frivolous or insubstantial requests for a hearing may be denied by the Regional Administrator.

Requests for public hearing should be addressed to: William Spaulding (WD–15J), U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604.

Any request for a public hearing shall include the following: (1) The name, address, and telephone number of the individual, organization, or other entity requesting a hearing. (2) A brief statement of the requesting person's interest in the Regional Administrator's determinations and of information that the requesting person intends to submit at such hearing. (3) The signature of the individual making the request; or, if the request is made on behalf of an organization or other entity, the signature of a responsible official of the organization or other entity.

Notice of any hearing shall be given not less than fifteen (15) days prior to the time scheduled for the hearing. Such notice will be made by the Regional Administrator in the **Federal Register** and in newspapers of general circulation in the State of Ohio. A notice will be sent to the person(s) requesting the hearing as well as to the State of Ohio. The hearing notice will include a statement of purpose, information regarding the time and location, and the address and telephone number where interested persons may obtain further information. The Regional Administrator will issue an order affirming or rescinding his determination upon review of the hearing record. Should the determination be affirmed, it will become effective as of the date of the order.

Should no timely and appropriate request for a hearing be received, and should the Regional Administrator not elect to hold a hearing on his own motion, these determinations shall become effective on June 22, 1998. Please bring this notice to the attention of any persons known by you to have an interest in these determinations.

All documents related to these determinations are available for inspection between the hours of 8:30 a.m. and 4:30 p.m., Monday through Friday, at the following offices:

Ohio Environmental Protection Agency, Division of Drinking and Ground Waters, 1800 WaterMark Drive, P.O. Box 1049, Columbus, Ohio 43215–1099, State Docket Officer: Mr. Bernie Clark, (614) 644–2752.

Safe Drinking Water Branch, U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604.

FOR FURTHER INFORMATION CONTACT: William Spaulding, Region 5, Safe Drinking Water Branch at the Chicago address given above, telephone 312/886–9262.

(Section 1413 of the Safe Drinking Water Act, as amended (1986), and 40 CFR 142.10 of the National Primary Drinking Water Regulations)

Dated: May 11, day of May 1998.

David A. Ullrich,

Acting Regional Administrator, Region 5.

[FR Doc. 98–13608 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–6100–2]

Common Sense Initiative Council (CSIC)

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notification of public advisory for the CSI council meeting, an open meeting.

SUMMARY: Pursuant to the Federal Advisory Committee Act, Public Law 92–463, notice is hereby given that the CSI Council will meet on the dates and times described below. The meeting is open to the public. Seating at the meeting will be on a first-come basis and limited time will be provided for public comment. For further information, please contact the individual listed below.

Common Sense Initiative Council Meeting—June 9, 1998

The Common Sense Initiative Council will hold an open meeting on Tuesday, June 9, 1998, from 8:30a.m. EST to 5:30p.m. EST. The meeting will be held at the Crystal City Sheraton, 1800 Jefferson-Davis Highway, Arlington, Virginia, 703–486–1111 or 1–800–325–3535.

The Council Agenda will focus on a variety of topics including: Discussion of five issue papers on Sector-Based Environmental Protection (SBEP) which will form the basis for the SBEP Action Plan, a Stakeholder Involvement Workgroup report, an update on the PrintSTEP project from the Printing Sector Subcommittee, recommendations from the Computer and Electronics Sector Subcommittee, discussion of Reinventing Environmental Information issues concerning data gaps, data quality, and burden reduction, and performance measures for CSI.

For further information concerning this Common Sense Initiative Council meeting, contact Kathleen Bailey, Designated Federal Officer, on (202) 260–7417, or email: bailey.kathleen@epamail.epa.gov.

INSPECTION OF SUBCOMMITTEE DOCUMENTS: Documents relating to the above Sector Subcommittee announcement will be publicly available at the meeting. Thereafter, these documents, together with the official minutes for the meeting, will be available for public inspection in room 3802M of EPA Headquarters, Common Sense Initiative Staff, 401 M Street, SW, Washington, DC 20460, telephone number 202–260–7417. Common Sense Initiative information can be accessed electronically on our web site at http://www.epa.gov/commonsense.

Gregory Ondich,

Acting Designated Federal Officer.

[FR Doc. 98–13615 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–6100–8]

Public Meeting To Discuss Adverse Environmental Impacts Resulting From Cooling Water Intake Structures

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of public meeting

SUMMARY: The Environmental Protection Agency will hold a public meeting to discuss issues associated with defining and measuring adverse environmental impacts from cooling water intake structures. The purpose of this meeting is to facilitate an exchange of information that will assist EPA in developing regulatory options for

minimizing adverse environmental impact. The public meeting is open to anyone wishing to attend.

SUPPLEMENTARY INFORMATION: In 1995, EPA entered into a Consent Decree that requires the Agency, no later than July 2, 1999, to propose regulations implementing Section 316(b) of the Clean Water Act, 33 U.S.C Section 1326(b), and to take final action with respect to the regulations no later than August 13, 2001. The Agency is currently developing these regulations for proposal. Section 316(b) provides that any standard established pursuant to sections 301 or 306 of the Clean Water Act and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. A primary purpose of Section 316(b) is to minimize the impingement and entrainment of fish and other aquatic organisms as they are drawn into a facility's cooling water intake.

The issues that EPA has developed for discussion fall into three categories: (1) Environmental Criteria: Defining and Assessing Adverse Environmental Impacts; (2) Plant Characteristics: Determining the Contribution to Adverse Environmental Impacts; and (3) Minimizing Adverse Environmental Impacts: Designing an Approach. The following is a potential list of issues for discussion at the June 29, 1998 public meeting:

(1) Environmental Criteria: Defining and Assessing Adverse Environmental Impact

- What constitutes an adverse environmental impact? Should the impact be defined in terms of actual and/or potential effects?
- What environmental parameters are most important for defining adverse environmental impacts?
- For which environmental parameters might qualitative or quantitative thresholds and/or decision criteria be developed for determining adverse impacts?
- What approaches and methods are most appropriate for assessing adverse environmental impact?

(2) Plant Characteristics: Determining the Contribution to Adverse Environmental Impact

- What factors related to the location, design, construction, and capacity of cooling water intake structures most significantly contribute to adverse environmental impacts? (For example: source waterbody type, flow rate, velocity, configuration of intake, type of technology at the intake.)
- For which such factors (e.g., velocity, flow rate, waterbody type, etc.) might qualitative or quantitative thresholds and/or decision criteria be developed?

(3) Minimizing Adverse Environmental Impact: Designing an Approach

- What information should be considered when designing an approach to minimize adverse environmental impacts.
- What are possible approaches to defining and measuring the cumulative effects of impingement and entrainment?

DATES: The public meeting will be held on Monday, June 29, 1998. The meeting will begin promptly at 10:00 a.m. and will end at approximately 4:30 p.m.

ADDRESSES: The meeting will be held at the Crystal City Marriott, 1999 Jefferson Davis Highway, Arlington, Virginia 22202. The Crystal City Marriott phone number is (703) 413–5500. The nearest Metro stop is Crystal City station on either the Blue or the Yellow Line. If you need overnight accommodations, please call the hotel directly. A block of 25 rooms is reserved for the night of Sunday, June 28, 1998. The rooms are listed under ''U.S. EPA 316(b) Meeting.''

FOR FURTHER INFORMATION CONTACT: Deborah Nagle, senior project manager, Office of Wastewater Management (4203), U.S. Environmental Protection Agency, 401 M Street S.W., Washington, D.C. 20460; phone number is (202) 260–2656 and E-mail address is nagle.deborah@epamail.epa.gov. To register for the meeting, please contact Betty Peterson of SAIC via FAX at (703) 903–1374 or via mail at 1710 Goodridge Drive (1–11–7), McLean, VA 22102. Please register by June 22, 1998.

Dated: May 14, 1998.

Tudor T. Davies,

Director, Office of Science and Technology.

[FR Doc. 98–13613 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[AD–FRL–6101–1]

Extension of Period of Submission of Section 111(d) Plans for Existing Municipal Solid Waste (MSW) Landfills

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Administrator has determined that it is necessary to extend the submission deadline for section 111(d) Plans for MSW landfills for the States of Arkansas and Oklahoma and for Chattanooga-Hamilton County, Tennessee as described below. The reasons for this action are set forth in the memorandum, *Supplemental Justification for Extending Municipal Solid Waste Landfill Section 111(d) Plan Submittals,* which is located in the docket and on EPA's website. These Plans, which are required under section 111(d) of the Clean Air Act (the Act) for existing landfills (40 CFR Part 60, subpart B), describe how the State or Local air pollution agency or Indian Tribe will implement the MSW landfill emission guidelines. The guidelines were promulgated on March 12, 1996 under 40 CFR Part 60, subpart Cc (61 FR 9905). The section 111(d) Plans were due December 12, 1996.

ADDRESSES: Office of Air Radiation Docket and Information Center (Air Docket 6102), Room M 1500, U.S. Environmental Protection Agency, Attention: Docket No. A–97–37, 401 M Street, S.W., Washington, D.C. 20460. The docket may be inspected between 8:00 a.m. and 5:30 p.m. on weekdays, and a reasonable fee may be charged for copying. The Air Docket may be called at (202) 260–7548. The EPA's Office of Air and Radiation Policy and Guidance website may be accessed at: http://www.epa.gov/ttn/oarpg/amend.html.

FOR FURTHER INFORMATION CONTACT: For Chattanooga-Hamilton County, Mr. Scott Davis, EPA Region IV, 61 Forsyth Street, S.W., Atlanta, GA 30303, telephone (404) 562–9127; for Arkansas or Oklahoma, Lt. Mick Cote, EPA Region VI, 1445 Ross Avenue, Suite 1200, Dallas, TX 75202, telephone (214) 665–7219.

SUPPLEMENTARY INFORMATION: The EPA promulgated standards of performance for new MSW landfills and emission guidelines for existing MSW landfills on March 12, 1996. These standards of performance and emission guidelines, which were developed under section 111 of the Act, regulate emissions of nonmethane organic compounds from MSW landfills. Section 111(d) of the Act requires States to submit a Plan to the EPA that addresses how States will regulate, implement and enforce standards of performance on existing MSW landfills and specifies when those Plans must be submitted. This requirement is codified under 40 CFR 60.23.

Section 60.27 of 40 CFR authorizes the EPA Administrator to extend the period for submission of a section 111(d) Plan whenever he or she determines it is necessary. Arkansas,

Oklahoma and Chattanooga-Hamilton County have shown good faith in developing and committing to submit their Plans in an expedited manner. Based on EPA's analysis of the State and local air pollution agency requests, Arkansas and Oklahoma and Chattanooga-Hamilton County are granted extensions until July 31, 1998. The memorandum, *Supplemental Justification for Extending Municipal Solid Waste Landfill Section 111(d) Plan Submittals,* mentioned previously, documents the States' efforts and explains why EPA is granting an extension for the section 111(d) Plan submittals to these States' and locality's air pollution agencies.

(Authority: 42 U.S.C. 7401–7671q)

Dated: May 13, 1998.

Carol M. Browner,

Administrator.

[FR Doc. 98–13609 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[OPP–30454; FRL–5789–1]

Certains Companies; Applications to Register Pesticide Products

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This notice announces receipt of applications to register pesticide products containing new active ingredients not included in any previously registered products pursuant to the provisions of section 3(c)(4) of the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), as amended.

DATES: Written comments must be submitted by June 22, 1998.

ADDRESSES: By mail, submit written comments identified by the document control number [OPP–30454] and the file symbols to: Public Information and Records Intregrity Branch, Information Resources and Services Division (7502C), Office of Pesticide Programs, Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. In person, bring comments to: Environmental Protection Agency, Rm. 119, CM #2, 1921 Jefferson Davis Hwy., Arlington, VA.

Comments and data may also be submitted electronically to: opp-docket@epamail.epa.gov. Follow the instructions under ''SUPPLEMENTARY INFORMATION.'' No Confidential Business Information (CBI) should be submitted through e-mail.

Information submitted as a comment concerning this notice may be claimed confidential by marking any part or all of that information as CBI. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. A copy of the comment that does not contain CBI must be submitted for inclusion in the public record. Information not marked confidential may be disclosed publicly by EPA without prior notice. The public docket is available for public inspection in Rm. 119 at the Virginia address given above, from 8:30 a.m. to 4 p.m., Monday through Friday, excluding holidays.

FOR FURTHER INFORMATION CONTACT: By mail: Cynthia Giles-Parker, Product Manager (PM-22), Registration Division (7505C), Office of Pesticide Programs, Environmental Protection Agency, 401 M St., SW., Washington, DC 20460. Office location, telephone number, and e-mail address: Rm. 247, CM #2, 1921 Jefferson Davis Highway, Arlington, VA 22202, (703 305–7740, e-mail: giles-parker.cynthia@epamail.epa.gov.

SUPPLEMENTARY INFORMATION: EPA received applications as follows to register pesticide products containing active ingredients not included in any previously registered products pursuant to the provision of section 3(c)(4) of FIFRA. Notice of receipt of these applications does not imply a decision by the Agency on the applications.

I. Products Containing Active Ingredients Not Included In Any Previously Registered Products

1. File Symbol: 71280–G. Applicant: Premium Compounded Products, LLC, 1208 East 12th St., Wilmington, DE 19802. Product Name: Migratrol R001. Plant growth regulator. Active ingredient: Cuprous chloride at 50 percent. Proposed classification/Use: None. For the control of root growth in nursery pots.

2. File Symbol: 71280–R. Applicant: Premium Compounded Products. Product Name: Cuprous Chloride. Plant growth regulator. Active ingredient: Cuprous chloride at 98.2 percent. Proposed classification/Use: None. For the control of root growth in nursery pots.

Notice of approval or denial of an application to register a pesticide product will be announced in the **Federal Register**. The procedure for requesting data will be given in the **Federal Register** if an application is approved.

Comments received within the specified time period will be considered before a final decision is made; comments received after the time specified will be considered only to the extent possible without delaying processing of the application.

II. Public Record and Electronic Submissions

The official record for this notice, as well as the public version, has been established for this notice under docket number [OPP–30454] (including comments and data submitted electronically as described below). A public version of this record, including printed, paper versions of electronic comments, which does not include any information claimed as CBI, is available for inspection from 8:30 a.m. to 4 p.m., Monday through Friday, excluding legal holidays. The official notice record is located at the address in ''ADDRESSES'' at the beginning of this document.

Electronic comments can be sent directly to EPA at:

opp-docket@epamail.epa.gov

Electronic comments must be submitted as an ASCII file avoiding the use of special characters and any form of encryption. Comment and data will also be accepted on disks in Wordperfect 5.1/6.1 or ASCII file format. All comments and data in electronic form must be identified by the docket number [OPP–30454]. Electronic comments on this notice may be filed online at many Federal Depository Libraries.

Authority: 7 U.S.C. 136.

List of Subjects

Environmental protection, Pesticides and pest, Product registration.

Dated: May 11, 1998.

James Jones,

Director, Registration Division, Office of Pesticide Programs.

[FR Doc. 98–13627 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–F

ENVIRONMENTAL PROTECTION AGENCY

[PB–402404–OH; FRL–5790–2]

Lead-Based Paint Activities in Target Housing and Child-Occupied Facilities; State of Ohio's Authorization Application

AGENCY: Environmental Protection Agency (EPA)

ACTION: Notice; request for comments and opportunity for public hearing.

SUMMARY: On April 13, 1998, the State of Ohio submitted an application for EPA approval to administer and enforce

training and certification requirements, training program accreditation requirements, and work practice standards for lead-based paint activities in target housing and child-occupied facilities under section 402 of the Toxic Substances Control Act (TSCA). This notice announces the receipt of Ohio's application, and provides a 45–day public comment period and an opportunity to request a public hearing on the application.

DATES: Submit comments on the authorization application on or before July 6, 1998. Public hearing requests must be submitted on or before June 5, 1998.

ADDRESSES: Submit all written comments and/or requests for a public hearing identified by tracking number ''PB-402404-OH'' (in duplicate) to: Environmental Protection Agency, Region 5, DT-8J, 77 West Jackson Blvd., Chicago, IL 60604.

Comments, data, and requests for a public hearing may also be submitted electronically to: turpin.david@epamail.epa.gov. Follow the instructions under Unit IV. of this document. No Confidential Business Information (CBI) should be submitted through e-mail.

FOR FURTHER INFORMATION CONTACT: Erik Maurer, Project Officer, Environmental Protection Agency, Region V, DT-8J, 77 West Jackson Blvd., Chicago, IL 60604, Telephone: (312) 353-1263, e-mail address: maurer.erik@epamail.epa.gov.

SUPPLEMENTARY INFORMATION:

I. Background

On October 28, 1992, the U.S. Congress passed Pub. L. 102-550 which included the Residential Lead-Based Paint Hazard Reduction Act of 1992. This Act amended TSCA (15 U.S.C. 2601 *et seq.*) by adding Title IV--Lead Exposure Reduction (15 U.S.C. 2681 *et seq.*).

Section 402 of TSCA authorizes and directs EPA to promulgate final regulations governing lead-based paint activities to ensure that individuals engaged in such activities are properly trained, that training programs are accredited, and that individuals engaged in these activities are certified and follow documented work practice standards. In lieu of the Federal program, a State or Tribe may seek authorization from EPA to administer and enforce their own lead-based paint activities program (TSCA, Title IV, section 404 (a)).

On August 29, 1996 (61 FR 45777) (FRL–5389–9), EPA promulgated the final TSCA section 402/404 regulations. On August 31, 1998, EPA will institute the Federal program in States or Tribes that do not have an authorized program. States and Tribes that choose to apply for program authorization must submit a complete application to the appropriate Regional EPA Office for review. These applications must be reviewed by EPA within 180 days of receipt of the complete application. To receive final program authorization, a State or Tribe must demonstrate that its program is at least as protective of human health and the environment as the Federal program and provides for adequate enforcement (section 404(b) of TSCA, 15 U.S.C. 2684 *et seq.*).

II. State Program Description Summary

Chapter 3742 of the Ohio Revised Code contains Ohio's lead licensing statutes. Chapters 3701-32 and 3701-82 of the Ohio Administrative Code contain the rules that amplify Chapter 3742. Together, the statutes and rules set up a licensing program operated by the Ohio Department of Health (ODH) for individuals engaged in lead-based paint activities. The statutes and rules also require ODH to approve lead testing laboratories, lead training providers, and lead abatement systems and products. In addition, they require physicians and laboratories to report lead poisoning cases to the State. Finally, they set up standards for the proper conduct of lead inspection, lead assessment, and lead abatement activities.

ODH licenses individuals in five lead disciplines: lead abatement contractor, lead abatement project designer, lead abatement worker, lead inspector, and lead risk assessor. To become licensed, potential contractors, workers, inspectors, and assessors must successfully complete an ODH-approved training course for the discipline in question, properly complete the licensing application, pay the appropriate license fee, and pass an independently administered state licensing examination. Registered sanitarians, sanitarians-in-training, certified industrial hygienists, and hygienists-in-training are exempted from the initial training requirement, but are required to pass the required certification exams and attend refresher training. ODH does not require project designers to pass a State licensing examination as a condition of licensing. Project designers are subject to rigorous education, experience, and training requirements as a condition of licensing.

A resident may conduct lead activities on his or her residence without a license. In most other cases, licensed personnel must conduct lead inspection, lead abatement, or lead assessment activities on a private residence or place of education or day care for a child under the age of 6. Any lead work conducted must comply with the work practices contained in rule 3701-32-02 of the Ohio Administrative Code. Rule 3701-32-02 references the suggested work practice procedures contained in the United States Department of Housing and Urban Development Guidelines for the Evaluation and Control of Lead-Based Paint in Housing (Guidelines). Pertinent chapters of the Guidelines are attachments to rule 3701-32-02 and other rules, and thus are part of Ohio's work practice standard.

Licensed personnel must prepare a lead inspection, lead risk assessment, or lead abatement report when conducting activities covered by Chapter 3742. The report must contain information recommended in the Guidelines and required by rule. All samples collected must be sent to an approved laboratory for analysis. Licensed personnel must keep copies of the report for a period of 3 years and are required to furnish reports to appropriate individuals.

III. Federal Overfiling

TSCA section 404(b) makes it unlawful for any person to violate, or fail, or refuse to comply with any requirement of an approved State or Tribal program. Therefore, EPA reserves the right to exercise its enforcement authority under TSCA against a violation of, or a failure, or refusal to comply with any requirement of an authorized State or Tribal program.

IV. Public Record and Electronic Submissions

The official record for this action, as well as the public version, has been established under the tracking number ''PB–402404–OH.'' Copies of this notice, the State of Ohio's authorization application, and all comments received on the application are available for inspection in the Region V office, from 8:30 a.m. to 5 p.m., Monday through Friday, excluding legal holidays. The application materials are available at: Toxics Program Section, Environmental Protection Agency, Region V, 8th floor, 77 West Jackson Blvd., Chicago, IL.

Electronic comments can be sent directly to EPA at:

turpin.david@epamail.epa.gov

Electronic comments must be submitted as an ASCII file, avoiding the use of special characters and any form of encryption. Comments and data will also be accepted on disks in WordPerfect 5.1/6.1 or ASCII file format. All comments and data in electronic form must be identified by

the tracking number ''PB–402404–OH.'' Electronic comments on this document may be filed online at many Federal Depository Libraries.

Authority: 15 U.S.C. 2682, 2684.

List of Subjects

Environmental protection, Hazardous substances, Lead, Reporting and recordkeeping requirements.

Dated: May 11, 1998.

David A. Ullrich,

Acting Regional Administrator, Region V.

[FR Doc. 98–13628 Filed 5–20–98; 8:45 am]

BILLING CODE 6560–50–F

OFFICE OF SCIENCE AND TECHNOLOGY POLICY

Meeting of the President's Committee of Advisors on Science and Technology

ACTION: Notice of meeting.

SUMMARY: This notice sets forth the schedule and summary agenda for a meeting of the President's Committee of Advisors on Science and Technology (PCAST), and describes the functions of the Committee. Notice of this meeting is required under the Federal Advisory Committee Act.

DATES AND PLACE: June 9, 1998. The White House Conference Center, Truman Room, Third Floor, 726 Jackson Place, NW., Washington, DC 20500.

TYPE OF MEETING: Open.

PROPOSED SCHEDULE AND AGENDA: The President's Committee of Advisors on Science and Technology (PCAST) will meet in open session on Tuesday, June 9, 1998, at approximately 10:00 a.m. to discuss (1) international S&T issues, (2) public understanding of science and technology, and (3) topics of Congressional concern. This session will end at approximately 3:30 p.m.

PUBLIC COMMENTS: There will be a time allocated for the public to speak on any of the above agenda items. Please make your request for the opportunity to make a public comment five (5) days in advance of the meeting. Written comments are welcome anytime prior to or following the meeting. Please notify Holly Gwin, OSTP Chief of Staff, at 202–456–6140 or fax your requests/comments to 202–456–6026.

FOR FURTHER INFORMATION CONTACT: For information regarding time, place, and agenda please call Holly Gwin, OSTP Chief of Staff, at 202–456–6140, prior to 3:00 p.m. on Friday, June 5, 1998. Please note that public seating for this meeting is limited, and is available on a first-come, first-served basis.

SUPPLEMENTARY INFORMATION: The President's Committee of Advisors on Science and Technology was established by Executive Order 12882, as amended, on November 23, 1993. The purpose of PCAST is to advise the President on matters of national importance that have significant science and technology content, and to assist the President's National Science and Technology Council in securing private sector participation in its activities. The Committee members are distinguished individuals appointed by the President from non-Federal sectors. The PCAST is co-chaired by the Assistant to the President for Science and Technology, and by John Young, former President and CEO of the Hewlett-Packard Company.

Dated: May 18, 1998.

Barbara Ann Ferguson,

Administrative Officer, Office of Science and Technology Policy.

[FR Doc. 98–13599 Filed 5–20–98; 8:45 am]

BILLING CODE 3170–01–M

FARM CREDIT ADMINISTRATION

[BM–14–May–98–02]

Interest Rate Risk Management

AGENCY: Farm Credit Administration.

ACTION: Proposed policy statement with request for comment.

SUMMARY: The Farm Credit Administration (FCA or Agency), through the FCA Board (Board), is issuing for comment a proposed policy statement that provides guidance on interest rate risk management practices to Farm Credit System (System) institutions and describes the Agency's approach to evaluating interest rate risk when making a determination of capital adequacy.

The proposed policy statement identifies key elements of sound business principles and practices for interest rate risk management by a System institution. The policy statement also provides criteria by which the Agency will evaluate the adequacy and effectiveness of a System institution's interest rate risk management.

DATES: Written comments should be received on or before June 22, 1998.

ADDRESSES: Comments may be mailed or delivered to Patricia W. DiMuzio, Director, Regulation and Policy Division, Office of Policy and Analysis, Farm Credit Administration, 1501 Farm Credit Drive, McLean, Virginia 22102–5090 or sent by facsimile transmission to (703) 734–5784. Comments may also be submitted via electronic mail to ''reg-comm@fca.gov.'' Copies of all communications received will be available for review by interested parties in the Office of Policy and Analysis, Farm Credit Administration.

FOR FURTHER INFORMATION CONTACT:

Andrew D. Jacob, Senior Policy Analyst, Office of Policy and Analysis, Farm Credit Administration, McLean, Virginia 22102–5090, (703) 883–4498, TDD (703) 883–4444,

or

Wendy R. Laguarda, Senior Attorney, Office of General Counsel, Farm Credit Administration, McLean, Virginia 22102–5090, (703) 883–4020, TDD (703) 883–4444.

SUPPLEMENTARY INFORMATION:

I. Background

The FCA's proposed Capital Phase III rule, in §§ 615.5180 and 615.5182, proposes that System banks and other System institutions (excluding the Federal Agricultural Mortgage Corporation) with interest rate risk implement appropriate risk management practices (*see* 62 FR 49623, Sept. 23, 1997). Proposed § 615.5181 provides that a System institution's board of directors (board) is responsible for maintaining effective oversight of interest rate risk management whereas senior management is responsible for ensuring that interest rate risk is properly managed. In the supplementary information to the proposed Capital Phase III rule, the Board stated its intention to provide additional guidance regarding sound interest rate risk management practices for A System institution.

In addition, proposed §§ 615.5350(b)(7) and 615.5355(a)(4) provide that the FCA may take action against an institution for failure to maintain sufficient capital for interest rate risk exposures. A System institution found to have high levels of exposure or weak interest rate risk management practices may be directed by the Agency to take corrective action, which may include raising additional capital, strengthening interest rate risk management expertise, improving interest rate risk management practices, reducing levels of exposure, or a combination thereof. The supplementary information to the proposed Capital Phase III rule states that a risk assessment approach will be used to evaluate a System institution's capital adequacy for interest rate risk and to determine what corrective action, if any, may be necessary. Additional guidance is now being provided by the FCA in this proposed policy statement.

Over the past several years, FCA examiners have considered the level of interest rate risk exposure, as well as the effectiveness of interest rate risk management practices, when concluding on an institution's capital adequacy and compliance with the requirements of § 615.5200(b)(7).[1] Considering previous examination results, the Agency does not anticipate that a System institution will be required to hold additional capital or enhance existing risk management practices for interest rate risk based solely on the Agency's implementation of the criteria contained in the proposed policy statement.

II. Discussion

The proposed policy statement addresses prudent interest rate risk management principles that the FCA expects a System institution to consider in its interest rate risk management processes. The FCA has emphasized these principles over the past several years in its examination, supervisory, and regulatory efforts. Moreover, many System institutions have already implemented interest rate risk management practices consistent with the principles contained in this policy statement. The policy statement also provides criteria by which the Agency will evaluate the adequacy and effectiveness of a System institution's interest rate risk management. In addition, the principles discussed here are consistent with the joint policy statement issued by other Federal financial institution regulatory agencies on interest rate risk management principles as applied to federally insured and supervised commercial banks and savings banks (*see* 61 FR 33166, June 26, 1996).[2]

Interest rate changes can affect an institution's earnings by changing net interest income and the level of other interest-sensitive income and operating expenses. Changes in interest rates also affect the underlying market value of an institution's assets, liabilities and off-balance sheet instruments. This occurs because the present value of a financial instrument's future cashflows, and in many cases the cashflows themselves, change when interest rates change. The combined effects of the changes in the present values of an institution's assets and liabilities reflect the change in an institution's underlying market value of equity.

Interest rate risk results from:

- Maturity or coupon adjustment timing differences of assets, liabilities, and off-balance sheet instruments (repricing or mismatch risk);
- Changes in the slope of the yield curve (yield curve risk);
- Imperfect correlation in the adjustment of the rates earned and paid on different instruments with otherwise similar repricing characteristics (basis risk); and
- Interest rate-related options embedded in assets, liabilities, and off-balance sheet instruments (options risk).

While interest rate risk is an inherent part of banking, it can become excessive and pose a significant threat to an institution's earnings and capital base. Accordingly, a well-managed risk management process that maintains interest rate risk within prudent levels is essential to the safety and soundness of a System institution.

III. Request for Comment

The Board requests comment on the Agency's proposed policy statement on interest rate risk management as set forth below in its entirety.

Policy Statement on Interest Rate Risk Management

BM–14–May–98–02

FCA–PS–##

Effective Date: None; Proposed Policy Statement with request for comment. Comment period is 30 days from publication in the **Federal Register**.

Effect on Previous Actions: None.

Source of Authority: Sections 5.9 and 5.17 of the Farm Credit Act of 1971, as amended.

I. Purpose

Interest rate risk is the exposure of a Farm Credit System (System) institution's financial condition to adverse movements in interest rates. This policy statement provides guidance to System institutions on prudent interest rate risk management principles. The policy statement also provides criteria by which the Farm Credit Administration (FCA or Agency) will evaluate the adequacy and effectiveness of a System institution's interest rate risk management.

II. Board of Directors' Responsibilities

Effective board of directors (board) oversight of an institution's interest rate risk activities is the cornerstone of a sound risk management process. The board should understand the nature and level of interest rate risks and how such risks relate to the overall business strategies of the institution. The board should also define its risk tolerance levels and expectations for interest rate risk management. To accomplish effective oversight, a board should, at a minimum, carry out the following responsibilities:

- Approve major business strategies and policies addressing interest rate risk, including establishing relevant risk limits, and integrating such strategies and policies into the institution's overall strategic and financial planning processes;
- Ensure that senior management implements a sound risk management process that facilitates the identification, measurement, monitoring, reporting, and control of interest rate risk;
- Monitor the institution's performance and overall interest rate risk profile to ensure that risk is maintained at prudent levels; and
- Ensure that adequate resources and proper control systems are devoted to interest rate risk management, including measurement activities.

III. Senior Management Responsibilities

Senior management is responsible for ensuring that interest rate risk is properly managed on both a long-range and day-to-day basis. In managing the institution's activities, senior management should, at a minimum:

- Develop and implement procedures that translate the board's major business strategies and policies addressing interest rate risk, including risk limits, into operating standards;
- Ensure adherence to the lines of authority and responsibility that the board has approved for managing, measuring, and reporting interest rate risk exposures;
- Oversee the implementation and maintenance of management information and other systems that appropriately manage and control interest rate risk; and
- Establish proper internal controls and audits over the interest rate risk management process.

An institution's board or senior management may delegate authority for implementing many aspects of board policy on risk management to an internal committee composed of qualified officers and staff members. Any such risk management committee should be a decision-making body involved in the acquisition, allocation, and pricing of the institution's resources in a manner consistent with both the goals established in a business plan and the risk tolerances established by the board.

IV. Interest Rate Risk Management Process

Effective control of interest rate risk requires a comprehensive management process that includes the following elements:

- Policies and procedures designed to control the nature and amount of interest rate risk that the institution assumes;
- A system for identifying and measuring interest rate risk;
- A system for monitoring and reporting interest rate risk; and
- A system of internal controls, review, and audit to ensure the integrity of the overall risk management process.

Each of the foregoing elements is discussed below.

A. Risk Limits

Each System institution should establish appropriate controls to effectively limit interest rate risk exposures within the risk tolerances established by the board. Established risk limits should be consistent

[1] Section 615.5200(b)(7) requires the board of directors of a System institution to consider other risk-oriented activities, such as interest rates risks, in developing its formal written capital adequacy plan.

[2] The Federal agencies that issued a joint policy statement on interest rate risk management are the Office of the Comptroller of the Currency, the Board of Governors of the Federal Reserve System, and the Federal Deposit Insurance Corporation.

with the overall measurement approach and should consider capital levels and earnings performance. Risk limits also should be clearly defined, ensure that exposures will not lead to an unsafe or unsound condition, be consistent with the nature and complexity of the institution's activities, and be evaluated within the institution's total risk-bearing capacity. The risk limits should address the potential impact of changes in market interest rates on both reported earnings and the market value of equity. Exceptions to established risk limits should be appropriately reported, approved, and controlled. In addition, risk limits should be reviewed at least annually to ensure that they remain appropriate. A System institution's board and senior management should further ensure that adequate operational procedures, controls, and risk limits are in place prior to introducing a new product, hedging, or position-taking strategy that has the potential to increase materially the institution's interest rate risk exposure.

B. Interest Rate Risk Identification and Measurement

Senior management should ensure the adequacy and completeness of the interest rate risk identification and measurement system. The quality and reliability of the identification and measurement system depends on the type of system used, the quality of the data, and various assumptions used in the model; therefore, close attention to these areas is needed. Senior management should ensure that the identification and measurement system:

- Enables management to recognize and identify in a timely and accurate manner risks arising from the institution's existing activities and from new business activities;
- Captures and measures all material sources of interest rate risk in ways that are consistent with the scope of the institution's activities [3] and considers all relevant repricing and maturity data such as current balances, contractual rates, principal payments, interest reset dates, maturities, index rates, and rate caps and floors;
- Contains assumptions that are clearly communicated to and understood by risk managers and the board of directors; and
- Measures an institution's vulnerability to loss under stressful market conditions, including a breakdown of key assumptions.

When assessing the scope of an institution's exposure, risk managers should consider the effect on earnings and, when appropriate, market value of equity. The effect on earnings is important because reduced earnings or losses can adversely affect liquidity and capital adequacy. The effect on market value of equity is important because adverse changes in the market value of assets, liabilities, and off-balance sheet instruments can affect the future performance and liquidity of a System institution.

C. Monitoring and Reporting

Each System institution must have adequate information systems for monitoring and reporting interest rate risk exposures. These systems should provide the board, senior management, and any risk management committee with clear, concise, and timely summaries of the institution's aggregate exposures, compare current exposure to policy limits, and allow for a determination of whether the institution holds sufficient capital in relation to the level of risk exposure. Risk reports should provide sufficient information for the board and senior management to assess exposure. The frequency of internal reporting should be determined by the board and senior management and should depend on the amount and complexity of an institution's level of risk.

D. Internal Controls and Audits [4]

Each System institution should maintain an effective system of internal controls as part of its interest rate risk management process. Controls should include a process for identifying and evaluating risk, establishing appropriate approval processes and exposure limits, and requiring reconciliations, audits, and other mechanisms designed to provide reasonable assurance that interest rate risk is managed in a safe and sound manner. The controls should ensure official lines of authority and the appropriate separation of duties to avoid conflicts of interest, and should ensure that personnel follow established policies and procedures.

An institution with more complex interest rate risk exposures should ensure that its interest rate risk process is audited on a regular basis. The audits should be conducted by qualified individuals who are independent of the function they are assigned to audit. The audits should test the effectiveness of controls and ensure appropriate follow-up with management where risk limits have been exceeded or deficiencies in interest rate risk management are identified. Audits of risk measurement systems and models should include assessments of the assumptions, parameters, and methodologies used. The audit results should be reported to the board and senior management.

E. Additional Guidance on the Interest Rate Risk Management Process

The interest rate risk management process will vary among each System institution in accordance with the level of its interest rate risk exposure. For instance, a System bank, direct lender association, or a service corporation that is exposed to and managing major sources of interest rate risk should employ comprehensive interest rate risk management and measurement practices that address all applicable elements of an effective interest rate risk management process discussed in this policy statement. These practices should ensure the establishment and maintenance of adequate controls over the identification, measurement, monitoring, and reporting of all sources of interest rate risk.

The formality and comprehensiveness of the risk management process will vary among each System association depending on the extent to which interest rate risk is centrally managed by its funding bank. For instance, a direct lender association that is managing some sources of interest rate risk locally and that has the potential for a moderate level of interest rate risk exposure should implement an interest rate risk program that includes:

(a) A policy that defines the board's interest rate risk tolerance arising from the sources of interest rate risk being managed locally and that sets risk limits from an earnings perspective and, if appropriate considering the sources of interest rate risk being managed, a market value of equity perspective;

(b) Procedures and practices established by senior management that adequately identify, measure, control, monitor, and report interest rate risks within the association's direct control;

(c) Procedures and practices established by senior management that ensure that the board understands the sources and exposure levels of interest rate risk;

(d) Reliable information systems and modeling capabilities that are commensurate with the nature of the interest rate risk being managed and that measure interest rate risk under various economic scenarios; and

(e) Consideration of interest rate risk exposures in the capital adequacy plan as required by § 615.5200(b)(7).

Finally, a direct lender association that relies on its funding bank to manage essentially all sources of interest rate risk and that has a minimal level of interest rate risk exposure should establish an interest rate risk management program that includes:

(a) A policy that establishes the board's tolerance for interest rate risk;

(b) Procedures to ensure that the board and senior management understand the sources and exposure levels of interest rate risk;

(c) Consideration of interest rate risk exposures in the capital adequacy plan as required by § 615.5200(b)(7); and

(d) An analysis, prepared at least annually, of potential earnings exposure to changing interest rates.

V. FCA's Capital Assessment for Interest Rate Risk

FCA examiners will assess an institution's capital adequacy for interest rate risk based on the evaluation of an institution's level of interest rate risk exposure and its risk management practices performed in accordance with the FCA's Financial Institution Rating System. The results of an institution's interest rate risk management measures will be considered when evaluating interest rate risk exposure levels.

[3] For a System institution with a high level of interest rate risk or a complex risk exposure, interest rate risk should be measured over a range of potential interest rate changes, economic scenarios, and yield curve shifts so as to effectively capture all material interest rate risk exposures (options, mismatch/repricing, basis, and yield curve). For a System association where the majority of interest rate risk is managed by the funding bank, any locally managed interest rate risk should be measured at least annually as part of its annual financial planning process.

[4] ''Audits'' is used here to refer to audits performed by either internal or external auditors. An institution can rely on qualified internal auditors to perform the audit functions by may wish to consider using external auditors if the interest rate risk exposures are complex and appropriate interest rate risk management practices and critical to controlling risk exposures at prudent levels.

Dated: May 15, 1998.

Floyd Fithian,

Secretary, Farm Credit Administration Board.

[FR Doc. 98–13626 Filed 5–20–98; 8:45 am]

BILLING CODE 6705–01–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) being Reviewed by the Federal Communications Commission

May 13, 1998.

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 July 20, 1998. 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, Federal Communications Commission, Room 234, 1919 M St., NW., Washington, DC 20554 or via internet to jboley@fcc.gov.

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s), contact Judy Boley at 202–418–0214 or via internet at jboley@fcc.gov.

SUPPLEMENTARY INFORMATION:

OMB Approval Number: 3060-0430.

Title: 47 CFR 1.1206, Permit-but-disclose proceedings.

Form No.: N/A.

Type of Review: Revision of a currently approved collection.

Respondents: Businesses or other for-profit, individuals or households, not-for-profit institutions, Federal Government, State, Local, or Tribal Government.

Number of Respondents: 10,000 responses.

Estimated Time Per Response: 1/2 hour.

Estimated Cost per Respondent: $25/response.

Total Annual Burden: 5,000 hours.

Frequency of Response: On occasion reporting requirement.

Needs and Uses: The Commission's rules require that a public record be made of ex parte presentations (*i.e.*, written presentations not served on all parties to the proceeding or oral presentations as to which all parties have not been given notice and an opportunity to be present) to decision-making personnel in ''permit-but-disclose'' proceedings, such as notice-and-comment rule makings and declaratory ruling proceedings. Persons making such presentations must file two copies of written presentations and two copies of a memorandum reflecting new data or arguments in oral presentations no later than the next business day after the presentation. Effective June 30, 1998, if ex parte presentations are filed electronically, only one copy need be filed. Parties to permit-but-disclose proceedings, including interested members of the public, use information regarding ex parte presentations to respond to the arguments made and data presented in the presentations. The responses may then be used by the Commission in its decision-making. The availability of the ex parte materials helps ensure that the interested persons have fair notice of presentations made to the Commission and the development of a complete record.

Federal Communications Commission.

Magalie Roman Salas,

Secretary.

[FR Doc. 98–13465 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–F

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection(s) Being Reviewed by the Federal Communications Commission

May 15, 1998.

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 July 20, 1998. 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, Federal Communications Commission, Room 234, 1919 M St., N.W., Washington, DC 20554 or via internet to jboley@fcc.gov.

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collection(s), contact Judy Boley at 202–418–0214 or via internet at jboley@fcc.gov.

SUPPLEMENTARY INFORMATION:

OMB Approval No.: 3060–0676.

Title: Policies and Rules Concerning Changing Long Distance Carrier (CC Docket No. 91–64), Section 64.1100.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for profit.

Number of Respondents: 75 respondents.

Estimated Time Per Response: 1.23 hours per response (avg.).

Frequency of Response: On occasion reporting requirement.

Total Annual Burden: 92.75 hours.

Estimated Annual Reporting and Recordkeeping Cost Burden: $0.

Needs and Uses: The rules require IXCs who generate customer PIC change

orders through telemarketing to independently verify, by one of the four alternative procedures, that customers have agreed to change their long distance service before submitting those orders on behalf of the customer to the local exchange carrier (LEC). The IXC must within three business days of the customer's request for a PIC change send each new customer an information package that contains information concerning the requested change and a postpaid postcard which the customer can use to deny, cancel, or confirm a service order. The information package required in the fourth alternative verification procedure is intended to provide a low cost verification procedure for small carriers that utilize telemarketing as a means of competing with large IXCs.

OMB Approval No.: 3060–0665.

Title: Section 64.702—Public Dissemination of Information by Providers of Operator Services.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for profit.

Number of Respondents: 436 respondents.

Estimated Time Per Response: 8 hours per response (avg.).

Frequency of Response: On occasion reporting requirement.

Total Annual Burden: 3488 hours.

Estimated Annual Reporting and Recordkeeping Cost Burden: $0.

Needs and Uses: 47 CFR Section 64.707 requires that operator service providers regularly publish and make available at no cost upon request from consumers written materials that describe any changes in operator services and choices available to consumers. A statute, 47 USC Section 226(d)(4)(B), required adoption of this rules. This requirement was a response to a widespread failure of operator service providers to provide information necessary for informed consumer choice in the marketplace. OSPs will provide this information primarily to consumers in the form of a written report that will be regularly updated at the OSP's discretion. Consumers will use this information to increase their knowledge of the choices available to them in the operator service marketplace.

OMB Approval No.: 3060–0515.

Title: Section 43.21(c)—Miscellaneous Common Carrier Letter Filing Requirement.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for profit.

Number of Respondents: 18 respondents.

Estimated Time Per Response: 1 hour per response (avg.).

Frequency of Response: Annual reporting requirement.

Total Annual Burden: 18 hours.

Estimated Annual Reporting and Recordkeeping Cost Burden: $0.

Needs and Uses: Pursuant to Section 43.21(c), each miscellaneous common carrier with operating revenues for a calendar year in excess of the indexed revenue threshold, as defined in 32.900, million must file a letter showing its operating revenues for that year and the value of its total communications plant at the end of that year. The letter must be filed not later than April 1 of the following year. The information is used by staff members to regulate and monitor the telephone industry and by the public to analyze the industry.

OMB Approval No.: 3060–0519.

Title: Rules and Regulations Implementing the Telephone Consumer Protection Act of 1991 (CC Docket No. 92–90).

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for profit.

Number of Respondents: 30,000 respondents.

Estimated Time Per Response: 31.2 hours per response (avg.).

Frequency of Response: On occasion reporting requirement.

Total Annual Burden: 936,000 hours.

Estimated Annual Reporting and Recordkeeping Cost Burden: $0.

Needs and Uses: In CC Docket No. 92–90, the Commission implemented final rules pursuant to the requirements of the Telephone Consumer Protection Act of 1991, Pub. L. 102–243, Dec. 20, 1991 (TCPA) which added Section 227 to the Communication Act of 1934, as amended, to restrict the use of automatic telephone dialing systems, artificial or prerecorded messages, facsimile machines, or other devices to send unsolicited advertisements. The rules require that telephone solicitors maintain and use company-specific lists of residential subscribers who request not to receive further telephone calls (company-specific do-not-call lists), thereby affording consumers the choice of which solicitors if any, they will hear from by telephone. Telephone solicitors also are required to have a written policy for maintaining do-not-call lists, and are responsible for informing and training their personnel in the existence and use of such lists. The rules require that those making telephone solicitations identify themselves to called parties, and that basic identifying information also be included in telephone facsimile transmissions. The Commission believes that these rules are the best means of preventing unwanted telephone solicitations.

OMB Approval No.: 3060–0169.

Title: Sections 43.51 and 43.53—Reports and Records of Communication Common Carriers and Certain Affiliates.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for profit.

Number of Respondents: 71 respondents.

Estimated Time Per Response: 84.91 hours per response (avg.).

Frequency of Response: On occasion reporting requirement.

Total Annual Burden: 6029 hours.

Estimated Annual Reporting and Recordkeeping Cost Burden: $0.

Needs and Uses: 47 CFR Sections 43.51 and 43.53 require common carriers to submit reports so that the FCC can monitor various activities of these carriers to determine the impact on the just and reasonable rates required by the Communications Act of 1934, as amended.

OMB Approval No.: 3060–0166.

Title: Part 42—Preservation of Records of Communication Common Carriers.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for profit.

Number of Respondents: 68 respondents.

Estimated Time Per Response: 2 hours per response (avg.).

Frequency of Response: On occasion reporting requirement.

Total Annual Burden: 136 hours.

Estimated Annual Reporting and Recordkeeping Cost Burden: $0.

Needs and Uses: Part 42 prescribes the regulations governing the preservation of records of communications common carriers that are fully subject to the jurisdiction of the FCC. The requirements are necessary to ensure the availability of carrier records needed by Commission staff for regulatory purposes.

OMB Approval No.: 3060–0391.

Title: Monitoring Program for Impact of Federal-State Joint Board Decisions.

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for profit.

Number of Respondents: 668 respondents.

Estimated Time Per Response: 2 hours per response (avg.).

Frequency of Response: On occasion reporting requirement.

Total Annual Burden: 1336 hours.

Estimated Annual Reporting and Recordkeeping Cost Burden: $0.

Needs and Uses: The Commission has a monitoring program which requires the periodic reporting by telephone companies and the National Exchange Carrier Association (NECA). Certain companies are required to submit information on network usage and growth. This information is generally maintained by all companies that settle on a cost basis. The information is being collected for the Commission by NECA. The information is used by the Commission, Joint Board, Congress and the general public to assess the impact of several Joint Board decisions.

OMB Approval No.: 3060–0470.

Title: Computer III Remand Proceeding: Bell Operating Company Safeguards, and Tier 1 LEC Safeguards (CC Docket No. 90–623) and Implementation of Further Cost Allocation Uniformity (MO&)).

Form No.: N/A.

Type of Review: Extension of a currently approved collection.

Respondents: Business or other for profit.

Number of Respondents: 18 respondents.

Estimated Time Per Response: 600 hours per response (avg.).

Freqency of Response: On occasion and annual reporting requirements.

Total Annual Burden: 10,800 hours.

Estimated Annual Reporting and Recordkeeping Cost Burden: $0.

Needs and Uses: 47 CFR Section 64.903(a) requires local exchange carriers with annual operating revenues that equal or exceed the indexed revenue threshold, as defined in Section 32.900 file a manual containing the information specified in Section 64.903(a)(1)–(6). Section 64.903(b) requires that carriers update their cost allocation manuals at least annually, except that changes to the cost apportionment table and to the description time reporting procedures must be filed at least 15 days before the carrier plans to implement the changes. The cost allocation manual is reviewed by the Commission to ensure that all costs are properly classified between regulated and nonregulated activity. Uniformity in the CAMs will help improve the joint cost allocation process. In addition, this uniformity will give the Commission greater reliability in financial data submitted by the carriers through the Automated Reporting Management Information System (ARMIS).

Federal Communications Commission.

Magalie Roman Salas,

Secretary.

[FR Doc. 98–13569 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL COMMUNICATIONS COMMISSION

Notice of Public Information Collection Submitted to OMB for Review and Approval

May 14, 1998.

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 collections, 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, 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 information techniques or other forms of information technology.

DATES: Written comments should be submitted on or before June 22, 1998. 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, Room 234, 1919 M St., N.W., Washington, DC 20554 or via internet to lesmith@fcc.gov.

FOR FURTHER INFORMATION CONTACT: For additional information or copies of the information collections contact Les Smith at 202–418–0214 or via internet at lesmith@fcc.gov.

SUPPLEMENTARY INFORMATION:

OMB Approval Number: 3060–0392.

Title: 47 CFR 1 Subpart J—Pole Attachment Complaint Procedures.

Form No: N/A.

Type of Review: Revision of a currently approved collection.

Respondents: Business and other for-profit; State, local and tribal governments.

Number of Respondents: 1,381.

Estimated Time Per Response: .5–35 hours.

Frequency of Response: On occasion reporting requirement; third party disclosure.

Cost to Respondents: $267,122 ($262,500 for outside legal counsel estimated at $150 per hour; $4,622 for filing expenses, postage and stationery costs, etc.).

Total Annual Burden: 3,047 hours.

Needs and Uses: On February 6, 1998, the Commission released a Report and Order, FCC 98–20, in CS Docket No. 97–151. In this Report and Order, the Commission adopts rules implementing Section 703 of the Telecommunications Act of 1996 relating to pole attachments. Section 703 requires the Commission to prescribe regulations to govern the charges for pole attachments used by the telecommunications carriers to provide telecommunications services. Information collection requirements regarding pole attachment provisions are used by the Commission to hear and resolve petitions for stay and complaints as mandated by Section 224 of the Communications Act of 1934. Information filed has been used to determine the merits of the petitions and complaints. Additionally, state certifications are used to make public notice of the state's authority to regulate the rates, terms and conditions for pole attachments.

Federal Communications Commission.

Magalie Roman Salas,

Secretary.

[FR Doc. 98–13568 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–10–P

FEDERAL COMMUNICATIONS COMMISSION

[CC Docket No. 96–45; DA 98–580]

Program To Monitor Impacts of Universal Service Support Mechanisms

AGENCY: Federal Communications Commission.

ACTION: Notice.

SUMMARY: On April 24, 1998, the Common Carrier Bureau issued a Public

Notice to solicit comment on its proposed program to monitor the impacts of universal service support mechanisms and to issue reports documenting the results of that monitoring program. Previously, on May 8, 1997, the Commission released a Report and Order implementing section 254 of the Communications Act, as amended, and creating a new set of universal service support mechanisms. The Public Notice describes a monitoring program, developed in consultation with the states, and that will enable the public, the Commission, and other policy makers to assess and evaluate the new universal service support mechanisms.

DATES: Comments to the Public Notice are due on or before May 26, 1998. Reply comments are due on or before June 10, 1998.

ADDRESSES: Comments and reply comments should be sent to the Office of the Secretary, Federal Communications Commission, 1919 M Street, N.W., Suite 222, Washington, D.C. 20554, with a copy to Scott Bergmann of the Common Carrier Bureau, Federal Communications Commission, 2033 M Street, N.W., Suite 500, Washington, D.C. 20554. Parties should also file one copy of any documents filed in this docket with the Commission's copy contractor, International Transcription Services, Inc. (ITS), 1231 20th St., NW, Washington, DC 20036, (202) 857–3800.

FOR FURTHER INFORMATION CONTACT: Thomas J. Beers, Deputy Chief of the Industry Analysis Division, Common Carrier Bureau, at (202) 418–0952, or Scott K. Bergmann, Industry Analysis Division, Common Carrier Bureau, at (202) 418–7102.

SUPPLEMENTARY INFORMATION: This is a summary of the Bureau's Public Notice released April 24, 1998 (DA 98–580). The full text of this Public Notice is available for inspection and copying during normal business hours in the FCC Reference Center, Room 239, 1919 M Street, Washington, D.C. 20554. The complete text also may be purchased from the Commission's copy contractor, International Transcription Service, Inc. (202) 857–3800, 1231 20th St., NW, Washington, DC 20036.

Summary of The Public Notice

1. On May 8, 1997, the Commission released a Report and Order, *Federal-State Joint Board on Universal Service,* CC Docket No. 96–45, FCC 97–157, (62 FR 32862, June 17, 1997) (hereafter *Universal Service Order*), implementing section 254 of the Communications Act, as amended, (47 U.S.C. Section 151 *et seq.*) and creating a new set of universal service support mechanisms. In the *Universal Service Order,* the Commission also decided to create a new program to monitor the universal service support mechanisms and to issue reports documenting the results of that monitoring program at least once a year. The Commission delegated responsibility for creating this monitoring program and for compiling the Monitoring Reports to the Common Carrier Bureau (Bureau), in consultation with the state staff of the Universal Service Joint Board. This Public Notice seeks comment on the proposed monitoring program.

2. The Commission instructed the Bureau to issue publicly available Monitoring Reports that are based on information provided by the administrator of the universal service support mechanisms to the Commission relating to the determination and amounts of payments made and monies received with respect to the universal service support mechanisms. With this guidance, the Commission delegated to the Bureau discretion over the exact content and timing of the Monitoring Reports. This Public Notice describes a monitoring program that we have developed in consultation with the states and that will enable the public, the Commission, and other policy makers, to assess and evaluate the new universal service support mechanisms. We issue this Public Notice to seek comment, particularly from those states, industry participants, and other members of the public not actively involved in CC Docket 96–45, on the proposed monitoring program. We note that, with some exceptions described below, the data included in the proposed Monitoring Reports are obtained pursuant to existing information collections, and thus impose no new reporting requirements on carriers, states, or any person other than the universal service administrator.

I. Background

3. In the 1996 Act, Congress adopted new section 254 of the Communications Act, as amended, and articulated a new statutory basis for federal universal service support mechanisms. Section 254 directs the Commission and states to establish support mechanisms to ensure the delivery of affordable telecommunications service to all Americans, including low-income consumers, eligible schools and libraries, and rural health care providers. The Commission, in the *Universal Service Order,* set forth a plan to meet all of the statutory requirements and to implement a universal service support system that will be sustainable over time.

II. Proposal

4. The new monitoring program will document and assess three aspects of the new universal service support mechanisms: (1) the contribution of support to the universal service support mechanisms; (2) the disbursement of support through the explicit universal service support mechanisms; and, (3) various measures of the impacts of the universal service support mechanisms. With respect to contributions, we propose to receive and report data on the monies collected by the administrator and to analyze the revenue data on which those contributions are based. This information will provide one measure of the overall size of the universal service support mechanisms. Similarly, with respect to disbursements, we propose to receive and report data on the monies distributed by the administrator and to analyze the various data (concerning, for example, costs to provide service in high cost areas, participation in low-income assistance plans, and provision of services through the new schools and libraries and rural health care support mechanisms) obtained by the administrator in the course of making disbursements. Finally, we propose to collect and report data on a number of measures (e.g., rates, penetration, usage, quality of service, and infrastructure), as a means of evaluating the effectiveness and efficiency of the universal service support mechanisms.

5. As a general matter, we seek comment on the proposals set forth in this Public Notice, including the organization, format, and content of individual sections of the Monitoring Report. In particular, we invite parties to address proposed additions to, or modifications of, sections included in the previous Monitoring Reports, as well as the proposed elimination of certain sections. We invite commenters to identify any additional information that they believe should be provided in the Monitoring Reports, and request that they explain why it would be in the public interest to add such information to the Monitoring Reports.

6. As we implement the new Monitoring Reports, we note that the Commission has delegated to the Bureau the authority to administer the monitoring program. Thus, the Bureau may change the content or timing of the Monitoring Reports if it is necessary or desirable to do so. In order to allow parties to submit, or review, materials and comments concerning the monitoring program at any time, we

have created a separate Bureau file number (CCB–IAD File No. 98–101) for all pleadings concerning the monitoring program.

7. In addition, we seek comment on whether we should supplement the Monitoring Report data on federal mechanisms with corresponding data on state universal service mechanisms. One of the Commission's fundamental goals in the *Universal Service Order* was to ''create sustainable and harmonious federal and state methods of continuously fulfilling universal service goals'' in cooperation with the Universal Service Joint Board. If we were to include data on state universal service support mechanisms in the Monitoring Reports, they would present a more comprehensive picture of the impact of both federal and state universal service support mechanisms on the industry and customers, materially enhancing the usefulness of the monitoring program. We note, however, that the federal universal service mechanisms are designed to address that portion of the cost of providing telecommunications services that is attributable to interstate service. Accordingly, and in light of these universal service goals, we seek comment on whether it would be appropriate, useful, and feasible to include state data in the Monitoring Reports.

8. Given the close relationship between the Commission's previous universal service support mechanisms and those new support mechanisms outlined in the *Universal Service Order*, we propose to adopt the structure and content of the past Monitoring Reports, *i.e.*, those issued in CC Docket 87–339, with modifications described herein. The new Monitoring Reports, proposed in the Public Notice, contain eleven sections, each described in the Public Notice. To address certain new aspects of the universal service support mechanisms, we propose to add four sections to the Monitoring Report. These new sections would report data on: (1) contributions to the universal service support mechanisms and accompanying industry revenue information; (2) the new rural health care mechanism; (3) the new schools and libraries mechanism; and (4) quality of service.

III. Procedural Issues

9. *Procedures for Filing.* Interested parties may file comments in CC Docket No. 96–45 not later than May 26, 1998. Reply comments may be filed not later than June 10, 1998. All filings should refer to the pleadings as Program to Monitor Impacts of Universal Service Support Mechanisms, CC Docket 96–45, CCB–IAD File No. 98–101. One original and four copies of all comments must be sent to Magalie Roman Salas, Secretary, Federal Communications Commission, 1919 M Street, NW., Washington, D.C. 20554. Two copies should also be sent to Ms. Terry Conway, Industry Analysis Division, Common Carrier Bureau, 2033 M Street, NW., Suite 500, Washington, D.C. 20554. Copies of documents filed with the Commission may be obtained from the International Transcription Service (ITS), 1231 20th Street, NW., Suite 140, Washington, D.C. 20036, (202) 857–3800. Documents are also available for review and copying at the Reference Center, Room 239, 1919 M Street, NW., Washington, D.C., Monday, from 9:45 a.m. to 4:30 p.m., and Tuesday through Friday from 9:00 a.m. to 4:30 p.m., (202) 418–0270.

10. This proceeding is a non-restricted proceeding. *See* 47 CFR 1.1200(a), 1.1206. Accordingly, *ex parte* presentations are permitted, provided that they are disclosed in conformance with the Commission's *ex parte* rules.

11. *Paperwork Reduction Act.* We note that substantially all of the data included in the proposed Monitoring Reports is obtained pursuant to existing information collections that have previously been approved by the Office of Management and Budget (OMB), pursuant to the Paperwork Reduction Act of 1995, Public Law No. 104–13. We tentatively conclude that certain proposals in this Public Notice might be subject to approval by the OMB, pursuant to the Paperwork Reduction Act, since they might impose new or modified collection requirements. Our analysis indicates that the following proposals may require OMB approval: (1) any collection of voluntarily submitted data from states concerning state universal service mechanisms (See paragraph 9 of the Public Notice); (2) any expansion of the Commission's local rate survey (See paragraphs 37–38 of the Public Notice); and (3) collection of certain usage data (See paragraph 43–45 of the Public Notice). All other proposals associated with the program either require responses from fewer than ten parties or are continuations of requirements that already have OMB approval. We invite the general public to comment on the new or modified information collections. Comments should address: (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 estimates; (c) ways to enhance the quality, utility, and clarity of the information collected; and (d) ways to minimize the burden of collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

Federal Communications Commission.

Peyton L. Wynns,

Chief, Industry Analysis Division.

[FR Doc. 98–13562 Filed 5–20–98; 8:45 am]

BILLING CODE 6712–01–P

FEDERAL EMERGENCY MANAGEMENT AGENCY

National Flood Insurance Program; Standard Flood Hazard Determination Form

AGENCY: Federal Emergency Management Agency (FEMA).

ACTION: Notice with request for comments.

SUMMARY: The Federal Emergency Management Agency gives notice of certain changes to the FEMA Standard Flood Hazard Determination form, which form is used to ensure that buildings and mobile homes located within an identified Special Flood Hazard Area (SFHA) will be covered by flood insurance. We invite public comment on the changes to the form.

DATES: Please submit any comments in writing on or before July 20, 1998.

ADDRESSES: Please submit any comments to the Rules Docket Clerk, Office of the General Counsel, Federal Emergency Management Agency, 500 C Street SW., room 840, Washington, DC 20472, (facsimile) (202) 646–4536, or (email) *rules@fema.gov*.

SUPPLEMENTARY INFORMATION: As part of our implementation of the National Flood Insurance Reform Act of 1994, FEMA published a final rule at 60 FR 35276, July 6, 1995, to establish a standard form for determining whether a building or mobile home is located in an SFHA, whether flood insurance is required, and whether federal flood insurance is available. The federal entities for lending regulation published a final rule (60 FR 35286, July 6, 1995) requiring use of the form. Use of the form by federally regulated lenders became mandatory on January 2, 1996. The OMB number for the current form expires on April 30, 1998 but OMB has extended the expiration date for an additional 90 days.

During the two years that this form has been in use, many users have commented on the form asking FEMA to make minor changes and clarifications. By separate rule published today in the **Federal Register** we have removed the form from 44 CFR part 65, Appendix A.

The form will continue in use and will continue to be available by written request, by fax-on-demand, and through the Internet at http://www.fema.gov/nfip/ mpurfi.htm. Removal of the form from the Code of Federal Regulations will enhance FEMA's ability to incorporate changes to the form outside of the rulemaking process, while continuing to provide full notice of the availability of the form to the public and to affected parties. By this notice we propose changes to the form and we request comments on the proposed changes from the public and from other Federal agencies.

Our proposed changes to the form include:

(1) a new reference to Otherwise Protected Areas (OPAs) in Section C, ''Federal Flood Insurance Availability.'' OPAs have restrictions on the sale of flood insurance similar to those on Coastal Barrier Resources Areas;

(2) a minor wording change to Section D, ''Determination,'' to simplify the statement as follows: The parenthetical phrase (Zones beginning with the letters ''A'' or ''V'') would be changed to (Zones containing the letters ''A'' or ''V'');

(3) numbering of the items listed in Sections A, B, and C to facilitate their reference in the instructions.

(4) revision of the instructions to include some clarifications and to include information on the form's availability via the FEMA fax-on-demand line and Internet site.

We notified users informally about the proposed revision by letter dated January 23, 1998, including lending regulators, federal agency lenders, government-sponsored enterprises for housing, flood zone determination companies, and lender trade associations.

Collection of Information

Title: Standard Flood Hazard Determination.

Type of Information Collection: Revision of a currently approved collection.

OMB Number: 3067–0264.

Form Number: Form Number 83–91, Standard Flood Hazard Determination.

Abstract. Federally regulated lending institutions (or third party), federal agency lenders, and government-sponsored enterprises for housing, complete this form when making, increasing, extending, renewing or purchasing any loan to document the factors considered when determining whether flood insurance is required and whether flood insurance is available. The statutory requirement for these parties to determine whether a building or mobile home securing a loan is located in an area having special flood hazards and whether flood insurance is available was first enacted in the Flood Disaster Protection Act of 1973. The Standard Flood Hazard Determination form was later required by the National Flood Insurance Reform Act of 1994 and provides a consistent method for documenting the required information.

Federally regulated lending institutions, federal agency lenders, and government-sponsored enterprises for housing process an estimated 12,000,000 loan applications each year that require the information. If they do not collect the information on the revised Standard Flood Hazard Determination form for each loan, then federally-backed loans may be inadequately insured against flood losses. Flood insurance is designed to decrease the financial impact of flooding on the federal government, on taxpayers, and on citizens in areas prone to flooding.

Affected Public: Business or other for-profit.

Estimated Total Annual Burden Hours. 4,000,000 hours.

FEMA form	Number of respondents (A)	Frequency of response (B)	Hours per response (C)	Annual burden hours (A×B×C)
81–93	12,000,000	1	.33	4,000,000

Estimated Cost. $99,000,000 (12,000,000 × .33 × $25 = $99,000,000).

Comments

FEMA does not collect the information contained on the Standard Flood Hazard Determination form. FEMA developed the form in response to a congressional mandate to establish a standard form for determining whether a building or mobile home is located in an SFHA and whether federal flood insurance is available. This form is considered a recordkeeping requirement. FEMA is soliciting written comments (a) to evaluate whether the proposed data collection is necessary for the proper performance of the agency, including whether the information has practical utility; (b) to 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; (c) to enhance the quality, utility, and clarity of the information to be collected; and (d) to 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.

Dated: May 14, 1998.

Michael J. Armstrong,

Associate Director for Mitigation.

FEMA Form 81–93, Federal Emergency Management Agency, Standard Flood Hazard Determination, as proposed to be amended, reads as follows:

BILLING CODE 6718–04–P

FEDERAL EMERGENCY MANAGEMENT AGENCY **STANDARD FLOOD HAZARD DETERMINATION**	*See The Attached Instructions*	*O.M.B. No. 3067-0264 Expires April 30, 1998*

SECTION I - LOAN INFORMATION

1. LENDER NAME AND ADDRESS	2. COLLATERAL *(Building/Mobile Home/Personal Property)* PROPERTY ADDRESS *(Legal Description may be attached)*	
3. LENDER ID. NO.	4. LOAN IDENTIFIER	5. AMOUNT OF FLOOD INSURANCE REQUIRED $

SECTION II

A. NATIONAL FLOOD INSURANCE PROGRAM (NFIP) COMMUNITY JURISDICTION

1. NFIP Community Name	2. County(ies)	3. State	4. NFIP Community Number

B. NATIONAL FLOOD INSURANCE PROGRAM (NFIP) DATA AFFECTING BUILDING/MOBILE HOME

1. NFIP Map Number or Community-Panel Number (Community name, if not the same as "A")	2. NFIP Map Panel Effective/ Revised Date	3. LOMA/LOMR	4. Flood Zone	5. No NFIP Map
		☐ yes _____ Date		

C. FEDERAL FLOOD INSURANCE AVAILABILITY ***(Check all that apply)***

1. ☐ Federal Flood insurance is available *(community participates in NFIP)*. ☐ Regular Program ☐ Emergency Program of NFIP
2. ☐ Federal Flood insurance is not available because community is not participating in the NFIP.
3. ☐ Building/Mobile Home is in a Coastal Barrier Resources Area (CBRA) or Otherwise Protected Area (OPA), Federal Flood insurance may not be available.

CBRA/OPA designation date: _____

D. DETERMINATION

IS BUILDING/MOBILE HOME IN SPECIAL FLOOD HAZARD AREA (ZONES CONTAINING THE LETTERS "A" OR "V")? ☐ YES ☐ NO

If yes, flood insurance is required by the Flood Disaster Protection Act of 1973.
If no, flood insurance is not required by the Flood Disaster Protection Act of 1973.

E. COMMENTS ***(Optional)***:

This determination is based on examining the NFIP map, any Federal Emergency Management Agency revisions to it, and any other information needed to locate the building/mobile home on the NFIP map.

F. PREPARER'S INFORMATION

NAME, ADDRESS, TELEPHONE NUMBER *(If other than Lender)*	DATE OF DETERMINATION

FEMA Form 81-93, OCT 97 **This form may be locally reproduced.**

[FR Doc. 98–13444 Filed 5–20–98; 8:45 am]
BILLING CODE 6718–04–C

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Bank Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Bank Holding Company Act of 1956 (12 U.S.C. 1841 *et seq.*) (BHC Act), Regulation Y (12 CFR Part 225), and all other applicable statutes and regulations to become a bank holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a bank or bank holding company and all of the banks and nonbanking companies owned by the bank holding company, including the companies listed below.

The applications listed below, as well as other related filings required by the Board, are available for immediate inspection at the Federal Reserve Bank indicated. The application also will be available for inspection at the offices of the Board of Governors. Interested persons may express their views in writing on the standards enumerated in the BHC Act (12 U.S.C. 1842(c)). If the proposal also involves the acquisition of a nonbanking company, the review also includes whether the acquisition of the nonbanking company complies with the standards in section 4 of the BHC Act. Unless otherwise noted, nonbanking activities will be conducted throughout the United States.

Unless otherwise noted, comments regarding each of these applications must be received at the Reserve Bank indicated or the offices of the Board of Governors not later than June 15, 1998.

A. Federal Reserve Bank of New York (Betsy Buttrill White, Senior Vice President) 33 Liberty Street, New York, New York 10045-0001:

1. Oswego County, MHC, Oswego, New York, Pathfinder Bancorp, MHC, Oswego, New York, to acquire or retain more than 50 percent of the voting shares of Oswego County MHC, Oswego, New York. In connection with this application, Oswego County, MHC, Oswego, New York, also has applied to become a bank holding company.

2. PASL Holding Corp., New York, New York, and MetBank Holding Corp., New York, New York; to become bank holding companies by acquiring more than 50 percent of the voting shares of Metropolitan National Bank, New York, New York.

3. RSI Bancorp, MHC, and RSI Bancorp, Inc., both of Rahway, New Jersey; to become bank holding companies by acquiring more than 50 percent of the voting shares of The Rahway Savings Institution, Rahway, New Jersey.

B. Federal Reserve Bank of Philadelphia (Michael E. Collins, Senior Vice President) 100 North 6th Street, Philadelphia, Pennsylvania 19105-1521:

1. Commerce Bancorp, Inc., Cherry Hill, New Jersey; to acquire 100 percent of the voting shares of Commerce Bank/Delaware, National Association, Wilmington, Delaware.

C. Federal Reserve Bank of Kansas City (D. Michael Manies, Assistant Vice President) 925 Grand Avenue, Kansas City, Missouri 64198-0001:

1. Gold Banc Corporation, Inc., Leawood, Kansas; to acquire 100 percent of the voting shares of Farmers State Bancshares of Sabetha, Sabetha, Kansas, and thereby indirectly acquire Farmers State Bank, Sabetha, Kansas.

Board of Governors of the Federal Reserve System, May 18, 1998.

Jennifer J. Johnson,

Deputy Secretary of the Board.

[FR Doc. 98–13642 Filed 5-20-98; 8:45 am]

BILLING CODE 6210-01-F

FEDERAL RESERVE SYSTEM

Sunshine Act Meeting

AGENCY HOLDING THE MEETING: Board of Governors of the Federal Reserve System.

FEDERAL REGISTER CITATION OF PREVIOUS ANNOUNCEMENT: 63 FR 26190, May 12, 1998.

PREVIOUSLY ANNOUNCED TIME AND DATE OF THE MEETING: 12:00 noon, Monday, May 18, 1998.

CHANGES IN THE MEETING: Addition of the following closed item to the meeting: Bank supervisory matter.

CONTACT PERSON FOR MORE INFORMATION: Joseph R. Coyne, Assistant to the Board; 202–452–3204.

SUPPLEMENTARY INFORMATION: You may call 202–452–3206 beginning at approximately 5 p.m. two business days before the meeting for a recorded announcement of bank and bank holding company applications scheduled for the meeting; or you may contact the Board's Web site at http://www.bog.frb.fed.us for an electronic announcement that not only lists applications, but also indicates procedural and other information about the meeting.

Dated: May 18, 1998.

Jennifer J. Johnson,

Deputy Secretary of the Board.

[FR Doc. 98–13688 Filed 5–18–98; 4:41 pm]

BILLING CODE 6210–01–P

FEDERAL RESERVE SYSTEM

Agency Information Collection Activities: Announcement of Board Approval Under Delegated Authority and Submission to OMB

SUMMARY:

Background. Notice is hereby given of the final approval of proposed information collections by the Board of Governors of the Federal Reserve System (Board) under OMB delegated authority, as per 5 CFR 1320.16 (OMB Regulations on Controlling Paperwork Burdens on the Public). Board-approved collections of information are incorporated into the official OMB inventory of currently approved collections of information. Copies of the OMB 83-Is and supporting statements and approved collection of information instruments are placed into OMB's public docket files. The Federal Reserve may not conduct or sponsor, and the respondent is not required to respond to, an information collection that has been extended, revised, or implemented on or after October 1, 1995, unless it displays a currently valid OMB control number.

FOR FURTHER INFORMATION CONTACT:

Chief, Financial Reports Section—Mary M. McLaughlin—Division of Research and Statistics, Board of Governors of the Federal Reserve System, Washington, DC 20551 (202-452-3829)

OMB Desk Officer—Alexander T. Hunt—Office of Information and Regulatory Affairs, Office of Management and Budget, New Executive Office Building, Room 3208, Washington, DC 20503 (202-395-7860)

Final approval under OMB delegated authority of the extension for three years, without revision, of the following reports:

1. Report title: Annual Survey of Eligible Bankers Acceptances

Agency form number: FR 2006

OMB Control number: 7100-0055

Frequency: annual

Reporters: U.S. commercial banks, U.S. branches and agencies of foreign banks, Edge and agreement corporations

Annual reporting hours: 46

Estimated average hours per response: 0.65

Number of respondents: 70

Small businesses are not affected.

General description of report: This information collection is voluntary (12 U.S.C. 248(a), 625, and 3105(b)) and is given confidential treatment (5 U.S.C. 522(b)(4)).

Abstract: The FR 2006 report provides information on eligible U.S. dollar acceptances that are payable in the

United States. The data are used for constructing the monetary aggregates, a nonfinancial debt aggregate, and a measure of short- and intermediate-term business credit.

2. Report title: Notice of Proposed Stock Redemption

Agency form number: FR 4008

OMB control number: 7100-0131

Frequency: on occasion

Reporters: bank holding companies

Annual reporting hours: 822

Estimated average hours per response: 15.5

Number of respondents: 53

Small businesses are not affected.

General description of report: This information collection is mandatory (12 U.S.C. 1844(c)) and is not given confidential treatment.

Abstract: The Federal Reserve System requires a bank holding company (BHC), other than a well-run company, to give written notice to its District Federal Reserve Bank before purchasing or redeeming its equity securities (collectively, redeeming or redemption) if the consideration paid for the proposed redemption and other redemptions over the preceding twelve months is 10 percent or more of the company's consolidated net worth. There is no formal reporting form; the BHC notifies the Federal Reserve by letter prior to making the proposed redemption. The Federal Reserve uses the information to fulfill its statutory obligation to supervise bank holding companies.

3. Report title: Notice Claiming Status as an Exempt Transfer Agent

Agency form number: FR 4013

OMB control number: 7100-0137

Frequency: on occasion

Reporters: banks, bank holding companies, and trust companies

Annual reporting hours: 16

Estimated average hours per response: 2

Number of respondents: 8

Small businesses are affected.

General description of report: This information collection is voluntary (15 U.S.C. 78q-l(c)(1)) and is not given confidential treatment.

Abstract: Banks, bank holding companies, and trust companies subject to the Federal Reserve's supervision that are low-volume transfer agents voluntarily file the FR 4013 notice on occasion with the Federal Reserve Board. Transfer agents are institutions that provide securities transfer, registration, monitoring, and other specified services on behalf of securities issuers. The purpose of the notice, which is effective until the agent withdraws it, is to claim exemption from certain rules and regulations of the Securities and Exchange Commission (SEC). The Federal Reserve uses the notices for supervisory purposes because the SEC has assigned to the Federal Reserve responsibility for collecting the notices and verifying their accuracy through examinations of the respondents. The notice is made by letter; there is no reporting form.

4. Report titles: Notice By Financial Institutions of Government Securities Broker or Government Securities Dealer Activities; Notice By Financial Institutions of Termination of Activities as a Government Securities Broker or Government Securities Dealer

Agency form numbers: FR G-FIN, FR G-FINW

OMB control number: 7100-0224

Frequency: on occasion

Reporters: state member banks, foreign banks, uninsured state-chartered branches or state-chartered agencies of foreign banks, commercial lending companies owned or controlled by foreign banks, and Edge corporations

Annual reporting hours: 33 (32 hours for FR G-FIN; 1 hour for FR G-FINW)

Estimated average hours per response: 1 hour for FR G-FIN; 15 minutes for FR G-FINW

Number of respondents: 37 (32 for FR G-FIN; 5 for FR G-FINW)

Small businesses are affected.

General description of report: This information collection is mandatory (15 U.S.C. 78o-5(a)(1)(B)(ii)) and is not given confidential treatment.

Abstract: Each financial institution that acts as a government securities broker or dealer is required to notify its appropriate regulatory authority of its broker-dealer activities, unless exempted from the notice requirement by Treasury Department regulation. Notification is required to record the intent to engage in government securities broker or dealer activity, to amend information submitted previously, and to record termination of such activity. Financial institutions use forms G-FIN and G-FINW to fulfill these notification requirements. The Federal Reserve uses the information in its supervisory capacity to measure compliance with the Government Securities Act of 1986.

Board of Governors of the Federal Reserve System, May 15, 1998.

William W. Wiles,

Secretary of the Board.

[FR Doc. 98–13641 Filed 5-20-98; 8:45AM]

Billing Code 6210-01-F

GENERAL ACCOUNTING OFFICE

Cost Accounting Standards Board Review Panel; Notice of Public Meeting

The Cost Accounting Standards Board (CASB) Review Panel was established in March 1998 to study, analyze, and assess the mission of the CASB in light of recent federal acquisition reforms. Formed at the request of Congress, the panel includes members from government, industry, and the accounting profession. It is anticipated that the panel will conclude its studies, analyses, and deliberations by the end of the current year and issue a report with recommendations to the Congress in early 1999. In conducting its work, the panel is seeking to obtain a broad spectrum of views from all interested parties including those in the government contracting community, academia, the accounting profession, and industry.

Meetings of the panel for the purpose of obtaining views from the public will take place on June 16 and June 17, 1998, between 1 p.m. and 5 p.m. and June 18, 1998, between 9 a.m. and 12:00 p.m. The panel is particularly interested in views concerning: (1) The Cost Accounting Standards Board's mission in a rapidly evolving integrated civil-military industry; (2) costs, benefits, and risk assessment in the application of cost accounting standards to government contractors (including differences based on industry, segment, type of cost, character of goods or services, contract type, and so forth); (3) the relationship of cost accounting standards to generally accepted accounting principles, activity-based cost systems, and cost allowability principles (including levels of complexity, overlap, duplication, conflict, and so forth).

The panel will convene at the U.S. General Accounting Office, Staats Briefing Room, 441 G Street, NW., Washington, DC 20548. The meetings will be open to the public, however, attendance at each session will be limited to the seating available. Entry to the GAO Building is obtained by clearance which must be granted in advance of the meeting. Those who would like to make presentations and those otherwise planning to attend should contact Mr. Ralph Dawn at 202–512–4501 by June 10, 1998. A written summary of remarks for those making presentations must be submitted by June 10, 1998, with a complete written statement to be submitted by June 15, 1998.

In addition, interested individuals are invited to make suggestions to the panel

regarding (1) topics that the panel should consider, and (2) names of individuals with applicable expertise that the panel should hear from. Those suggestions should be sent via the CASB Review Panel's web page at http://www.gao.gov or by leaving recorded messages at 202–512–4501.

Ralph C. Dawn,

Staff Director, Cost Accounting Standards Board Review Panel.

[FR Doc. 98–13638 Filed 5–20–98; 8:45 am]

BILLING CODE 1610–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

Agency Information Collection Activities: Proposed Collections; Comment Request

The Department of Health and Human Services, Office of the Secretary will periodically publish summaries of proposed information collections projects and solicit public comments in compliance with the requirements of Section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995. To request more information on the project or to obtain a copy of the information collection plans and instruments, call the OS Reports Clearance Officer on (202) 690–6207.

Comments are invited on: (a) Whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information shall have practical utility; (b) the accuracy of the agency's estimate of the burden of the proposed collection of information; (c) ways to enhance the quality, utility and clarity of the information to be collected; and (d) ways to minimize the burden of the collection of information on respondents, including through the use of automated collection techniques or other forms of information technology.

Proposed Projects 1. Study of Medicare Home Health Practice Variations—NEW—The Office of the Assistant Secretary for Planning and Evaluation is proposing a study which will examine how patient, provider, agency, market and regulatory factors affect variations in home health practice. A sample of 48 Medicare-certified home health agencies (from eight states) will be studied. Within each of these agencies, 24 patients (with congestive heart failure or diabetes) will be sampled. The results will identify agency characteristics and behaviors that are related to differences in lengths of stay for patients with similar risk factors.— Respondents: For-profit, Non-profit Institutions; Burden Information for the Administrator Questionnaire—Number of Respondents: 48; Burden per Response: 36 minutes: Burden: 29 hours—Burden Information for the Care Provider Questionnaire—Number of Responses: 1152; Burden per Response: 1 hour: Burden: 1152 hours—Total Burden: 1181 hours.

Send comments to Cynthia Agens Bauer, OS Reports Clearance Officer, Room 503H, Humphrey Building, 200 Independence Avenue S.W., Washington, DC, 20201. Written comments should be received within 60 days of this notice.

Dated: May 11, 1998.

Dennis P. Williams,

Deputy Assistant Secretary, Budget.

[FR Doc. 98–13476 Filed 5–20–98; 8:45 am]

BILLING CODE 4150–04–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary Assistant Secretary for Planning and Evaluation Notice Inviting Applications for New Award for Fiscal Year 1998

AGENCY: The Office of the Assistant Secretary for Planning and Evaluation (ASPE), Office of the Secretary (OS).

ACTION: Announcement of the availability of funds and request for applications from states to determine the status of Temporary Assistance to Needy Families (TANF) recipients after they leave the TANF caseload, eligible families who are diverted before being enrolled, or eligible families who fail to enroll.

SUMMARY: The Office of the Assistant Secretary for Planning and Evaluation (ASPE), with support from the U.S. Department of Labor and the Economic Research Service of the U.S. Department of Agriculture, announces the availability of funds and invites applications for research into the status of individuals and families who leave the TANF program, who apply for cash welfare but are never enrolled because of non-financial eligibility requirements or diversion programs, and/or who appear to be eligible but are not enrolled (hereafter jointly referred to as welfare leavers). Approximately eight to ten States or counties will receive funding that will enable them to track and monitor how individuals and their families do in the first year after they leave welfare and provide a foundation for longer follow-up. States may choose any method for such tracking, including the linking of administrative data, surveys or other methods as appropriate. We are particularly interested in learning about individuals' ability to obtain employment and the support provided by their earnings, public programs besides TANF, and other sources. The funds could support a newly designed project or could be used to add new data sources and analyses to an existing project.

In addition, ASPE announces the availability of supplementary funding from the Office of Policy Development and Research (PD&R) of the U.S. Department of Housing and Urban Development (HUD) to track the consequences of welfare reform for low-income families with children who receive housing assistance. These funds will only be available to ASPE Grantees.

CLOSING DATE: The deadline for submission of applications under this announcement is July 6, 1998.

MAILING ADDRESS: Application instructions and forms should be requested from and submitted to: Grants Officer, Office of the Assistant Secretary for Planning and Evaluation, Department of Health and Human Services, 200 Independence Avenue, SW., Room 405F, Hubert H. Humphrey Building, Washington, D.C. 20201, Telephone: (202) 690–8794. Copies of this program announcement and many of the required forms may also be obtained electronically at the ASPE World Wide Web Page: http://aspe.os.dhhs.gov. Requests for forms and administrative questions will be accepted and responded to up to 10 working days prior to closing date of receipt of applications. Application submissions may not be faxed or submitted electronically.

The printed **Federal Register** notice is the only official program announcement. Although reasonable efforts are taken to assure that the files on the ASPE World Wide Web Page containing electronic copies of this Program Announcement are accurate and complete, they are provided for information only. The applicant bears sole responsibility to assure that the copy downloaded and/or printed from any other source is accurate and complete.

FOR FURTHER INFORMATION CONTACT: Administrative questions should be directed to the Grants Officer at the address or phone number listed above. Technical questions should be directed to Christopher Snow, DHHS, ASPE, Telephone, 202–690–6888 E-mail, csnow@osaspe.dhhs.gov. Written technical questions may also be faxed to 202–690–6562 or may be addressed to

Mr. Snow at the following address. Office of the Assistant Secretary for Planning and Evaluation, Department of Health and Human Services, 200 Independence Avenue, S.W., Room 404E, Hubert H. Humphrey Building, Washington, D.C. 20201.

Part I Supplementary Information

Legislative Authority

This grant is authorized by Section 1110 of the Social Security Act (42 U.S.C. 1310) and awards will be made from funds appropriated under PL 105–78 Department of Health and Human Services Appropriations Act, 1998.

Eligible Applicants

Given the nature of the research involved, competition is open only to State agencies and counties that administer TANF programs with populations greater than 500,000. Consortia of States are also encouraged to apply, as long as a single State agency is identified as the lead and agrees to handle grant funds and sub-granting. Public or private nonprofit organizations, including universities and other institutions of higher education, may collaborate with States in submitting an application, but the principal Grantee will be the State. Private for-profit organizations may also apply jointly with States, with the recognition that grant funds may not be paid as profit to any recipient of a grant or subgrant.

Available Funds

Approximately $2,350,000 is available from ASPE, in funds appropriated for fiscal year 1998. ASPE anticipates providing approximately eight to ten awards of between $200,000 and $250,000 each. If additional funding becomes available in fiscal years 1998 or 1999 additional projects may be funded or some projects may receive second year funding to allow extended tracking of families who left the TANF caseload or were diverted from the roles.

The Economic Research Service (ERS) of the U.S. Department of Agriculture has provided a portion of the total funding in order to support analyses of outcomes for families in rural areas, particularly rural areas with historically high concentrations of poverty. ERS funding under this ASPE announcement is separate from the ERS grant program—''Status of Households who Leave the Food Stamp Program.'' If applicant is applying to both grant programs (ASPE and ERS) the application should specify how the projects will be coordinated. The U.S. Department of Labor has also provided a portion of the total funding, in order to support greater use of in-depth, in-person interviews.

Office of Policy Development and Research (PD&R) of the U.S. Department of Housing and Urban Development (HUD) expects to make available up to $350,000 over and above the ASPE awards through supplemental grants for analyses including assisted housing recipients.

Background

Since 1993, AFDC caseloads have seen unprecedented declines. A portion of the decline can be attributed to increasing numbers of former recipients leaving the rolls. The remainder is comprised of fewer families entering the rolls than in previous periods. While it is likely that a strong economy has enabled many people to move in to the workplace, or to remain there, there is little beyond anecdotes to indicate for certain what has happened to them. Under the Personal Responsibility and Work Opportunity Reconciliation Act (PRWORA), with its time limits and emphasis on employment, the trend in caseload declines may continue.

The studies funded under this announcement build on previous ASPE sponsored data-linkage and research projects. In FY 1996 and 1997, ASPE awarded grants to five states (and one county) for the purpose of linking administrative databases from multiple programs in order to study the interactions between programs and the use of multiple sources of assistance by recipients. Also in FY 1997, ASPE and ACF sponsored a study on the effects of formal and informal TANF diversion programs on recipients and on participation in other public programs, particularly Medicaid.

Administrative records provide a reliable estimate of individuals receiving benefits. Historically, however, AFDC administrative records have only tracked the status of individuals and families while they were receiving welfare. Examining the situation of recipients once they leave, or of applicants who never receive cash welfare, takes additional efforts by welfare agencies, such as linking public assistance databases to those that store earnings data (e.g. unemployment insurance records) and data on other public programs (e.g. Food Stamps, Medicaid, Child Care).

A number of issues may be identified using linked administrative data, including whether the adults are employed, how long they are employed, how much they are earning, whether their earnings have increased, and whether they have returned to TANF. It may also be possible to provide an indication whether family well-being has improved, worsened or been maintained, by examining families' involvement with the child welfare system, whether they continue to receive Medicaid and child care subsidies, have any food or housing insecurity, and receive other federal, state or community sources of support they have, etc. (See suggested topical areas below).

Many states have begun planning or implementing efforts to track welfare reform outcomes on recipients. These efforts have employed a range of methods, which include linking administrative databases, telephone or in person interviews or surveys, and focus groups—Maryland and South Carolina, for example, have recently released preliminary reports tracking some characteristics of families who have left their public assistance programs, using very different methodologies.

Maryland's report relied on linked administrative data from TANF, Child Welfare and the Unemployment Insurance system to look at: history of welfare receipt; reasons for case closure, including sanctions; employment and earnings over time both before and after case closure; the industries in which welfare leavers were employed; and the incidence of child welfare investigations and foster care placements among children in families who had left welfare.

Although the Maryland study was not intended to attribute cause and effect, it allowed cross-tabulations of workforce success and recidivism against length of last welfare spell and months of lifetime welfare receipt, and against work history before, during and after welfare. In the summer of 1998, Maryland plans to supplement and enrich these results with a survey to explore outcomes that cannot be measured with administrative data.

South Carolina tracked welfare leavers who had been subject to work requirements or who had voluntarily sought work using two state-designed and administered sample surveys. An important feature of South Carolina's approach was the great effort made to achieve a high response rate and therefore reduce response bias. Surveyors attempted to contact former welfare families several times by telephone, and if still unsuccessful, sent out interviewers for in person interviews. These techniques resulted in 77% and 78% response rates for the two surveys.

Because survey instruments were used rather than administrative data,

South Carolina has been able to gather rich information on former welfare recipients and their families. For example, they were able to determine whether the recipients' perceived reasons for case closure corresponded to the administrative record. When they examined employment outcomes, they gathered a much richer set of employment outcomes than is typically available through administrative data (e.g. Unemployment Insurance wage records). They were also able to get reasons for unemployment and barriers to work, wages and work hours, rather than aggregated earnings, and to determine the actual jobs held by former recipients, rather than simply the industry in which they worked.

Another area that South Carolina examined through their surveys was child care, including availability, type and location (family, neighbors, commercial centers, etc.), costs and funding sources, and the barrier that lack of child care or child care problems presented in finding and maintaining employment. Other areas included medical insurance coverage, transportation, children's educational status, and use of and knowledge of other public services, including Medicaid, Food Stamps, child care subsidies, rent subsidies or public housing, adult education, mental health and substance abuse services.

Finally, South Carolina asked recipients about deprivations that they had encountered, whether while on welfare or since exit, including inability to pay for rent, utilities or food, homelessness, car repossessions, lack of needed medical treatment and changes in children's schools or living arrangements.

Part II Purpose and Responsibilities

Purpose

The purpose of this announcement is to partner with States and support State efforts to track former TANF recipients and their families, families who apply for cash welfare but are never enrolled because of non-financial eligibility requirements or diversion programs, and/or families who appear to be eligible but are not enrolled. In particular, ASPE would like to support State efforts to ascertain the sources of support used by these families, including employment, their use of public programs, their well-being, the extent of any resource insecurity or deprivation and the circumstances of children.

A proposed study should include at least two cohorts. For example, the first cohort of families could be those who left the roles or were diverted at least one full year before the second calendar quarter of 1998. This would allow the Grantee to immediately look retrospectively at a full year of families' experiences, and to complete their initial analysis of this cohort in time for the interim report. The Grantee should record the characteristics of families at the point of closure, including the reason for closure. The former recipients and their families should then be identified and tracked in administrative records from multiple programs and/or through other data-gathering techniques for the subsequent 12 months. In the interest of cross-State comparability, ASPE would prefer that if possible this cohort be drawn from families who left or were diverted during the last quarter of calendar year 1996 and tracked during the full calendar year 1997.

The data sources and analysis used for the second cohort may be more extensive than those used for the first, since more time is available. For example, applicants may propose to enrich their administrative data by linking individual records with survey data or other data sources. Additionally, the Grantee would be able to follow this cohort during the term of the project, at least in part, rather than looking solely retrospectively. Richness of data will be an important criterion under which proposals are evaluated.

ASPE understands that there is a great degree of variation in State programs and in the amount and scope of data available to states. It is therefore highly unlikely that every applicant would be able to address all of the issues and questions raised in the following section. It is also unlikely that every applicant can propose a study that includes both welfare leavers and families diverted from the rolls.

However, subgroup analyses contrasting cases that close due to earnings, sanctions and time limits, as well as those which are never enrolled due to formal or informal diversion practices are strongly encouraged. Comparisons of characteristics and outcomes of rural versus urban populations and analyses special populations (e.g. the disabled, substance abusers) are also of interest.

One type of possible subgroup analysis would involve HUD assisted families. Approximately 1.1 million households receiving AFDC benefits before the enactment of PRWORA were also receiving HUD housing assistance. Because of this substantial overlap in populations served, PD&R wishes to obtain reliable evidence about the interaction of welfare reform with housing programs. Grantees receiving supplementary funding from PD&R will receive, subject to satisfactory execution of confidentiality agreements, a file containing identifiers of families with children, (or a more narrowly targeted group, as defined by the Grantee) living in public and assisted housing in the state as of a month designated by the Grantee. PD&R is interested in the experience of these families relative to families not assisted; it is also interested in the experience of families living in public housing relative to the experience of families receiving tenant-based assistance or families receiving Section 8 project-based assistance.

Because the focus of TANF is moving families to work, and because employment and earnings levels are such important precursors to well-being, the one required focus will be on the employment and earnings status of the affected individuals. All applicants must describe how they intend to address employment issues. Examples of questions of interest regarding employment and earnings include:

- How long does it take recipients and former recipients to find jobs? What types of jobs do they hold? How long do they stay in their jobs? If they are not employed, why not? What level of wages do they receive and how much do they receive in total earnings? What sort of work schedules do they have? What, if any, employer provided fringe benefits and training are available to them? What fringe benefits do they actually receive? Are there any significant barriers to accessing these fringe benefits?

Additional policy relevant topical areas which States may wish to address include child care usage, medical insurance coverage, receipt of other public benefits and child and family well-being. While each of the topical areas presented below present a range of issues, the suggested questions are in no way meant to be exhaustive. If prospective applicants have additional questions which they feel are relevant within the context of welfare reform, they are encouraged to raise them in their proposal. Again, richness of data is strongly encouraged and will be an important criterion under which proposals are evaluated.

Topical areas which applicants may wish to address, with examples of potential questions.

- *Food Stamps*—What role do food stamps play in supporting welfare leavers?
- *Family support*—What role do family resources and support play? What role do child support payments play?

• *Health insurance*—Do families have access to health insurance? From what source (employer provided, Medicaid, CHIP)? Are premiums or copays are required? Which family members are covered?

• *Child care*—To what extent is child care available to welfare leavers and what are the most common arrangements? What is the source of payment for childcare? What is the quality of these arrangements? To what extent are eligible child care recipients taking advantage of services? How do child care arrangements change once people leave welfare, either via work or due to sanctions and time limits?

• *Child Welfare/Foster Care*—What is the incidence of children found to have been neglected or abused, or to enter foster care, following the elimination of financial assistance to a family? How does this compare with their experiences while on welfare?

• *Child living arrangements/Kinship Care*—Do we observe changes in child living arrangements that are correlated with the imposition of time limits, sanctions and work requirements? For instance, do we find that increasing numbers/proportions of children are being cared for by relatives other than parents (either as assistance units headed by relatives or as child-only assistance units)?

• *Diverted cases*—What types of families are diverted and for what reasons? Of cases diverted, how many later come onto welfare? What alternative sources of support do they have?

• *Awareness of benefits*—To what extent are families aware of the availability of transitional and other benefits available to welfare leavers and those diverted from ongoing cash assistance? To what extent do they avail themselves of these benefits?

• *Recidivism*—How many families return to welfare, when and why? What effect do other issues listed here appear to have on recidivism?

• *Attitudes*—What are former recipients attitudes toward work, TANF, leaving TANF, and their situation?

• *Health Insecurity*—What is the health status of each family member? Do they have difficulties accessing health care?

• *Food Insecurity*—Do families report having enough money for food? Do they rely on food pantries?

• *Housing Insecurity*—Have families been forced to double-up or move in with relatives? Do they report not always having enough money to pay the rent? Have they experienced periods of homelessness?

• *Barriers to self-sufficiency*—Do former recipients appear to face any of the following barriers to employment: disability, illiteracy, limited English proficiency, domestic violence, mental illness or substance abuse.

• *Reasons for case closure*—What reason is recorded in the case record? What reason is reported by the recipient?

Grantee Responsibilities

1. Prior to completion of the final work plan (analysis plan), the Grantee should meet with relevant federal personnel, other Grantees and invited experts in Washington, D.C., to discuss the preliminary methodology and design of the research project including what research questions will be answered and what methodology the Grantee will employ to answer the questions.

As part of this process, all the Grantees will take part in a joint discussion of their proposed study designs. This will encourage a level of comparability of issues to be addressed and data created across the various projects, as well as allow for peer-to-peer contacts and technical assistance among Grantees.

2. No later than 30 days after this meeting and consultation the Grantee should submit an outline progress to date, if any, and a final work plan that is based on and updates the work plan submitted in the original application.

3. A second meeting will be planned later in the grant period in Washington, D.C., to discuss preliminary findings and the format for the interim and final reports (for Grantees outside the Washington, D.C. area this may take place by telephone). A preliminary draft of the interim report, including initial results, if any, and a plan for any further data collection and analysis, should be delivered to the Federal Project Officer within 90 days of submission of the final work plan. The Federal Project Officer will return comments on the draft interim report to the Grantee and a minimum of three (3) copies of an interim report should be delivered to the Grants Officer within 30 days. One of these copies must be unbound, suitable for photocopying; if only one is the original (has the original signature, is attached to a cover letter, etc.), it should not be this copy.

4. After completing their analysis, the Grantee will prepare a final report describing the procedures used to conduct the analysis, barriers encountered in completing the project and the results of the analysis. A draft of this report should be delivered to the Federal Project Officer before the completion of the project. The Federal Project Officer will return comments on the draft report to the Grantee and at least three (3) copies of a final report should be delivered to the Grants Officer before the completion of the project. One of these copies must be unbound, suitable for photocopying; if only one is the original (has the original signature, is attached to a cover letter, etc.), it should not be this copy.

5. To encourage wider analysis, Grantee will make all data available to the research community. ASPE prefers that this result in a public-use data file. In preparing the public-use data file, data should be edited as appropriate to ensure confidentiality of individuals. If the applicant feels that provision of a public-use data file is impossible, the application should explain why and should fully articulate how the applicant will make the data available to qualified researchers and to ASPE. In either case, the plan for data dissemination will be evaluated and scored during the evaluation of proposals.

ASPE Responsibilities

1. ASPE will convene one to two meetings of Grantees, federal personnel, and relevant experts in the areas the Grantees choose to address. The first meeting will take place within 60 days of award and will allow for technical assistance and peer-to-peer contacts before final research design decisions have been made, as well as assuring that data constructs meet some standard of validity and comparability. A second meeting may be held approximately 6 to 8 months into the grant period to provide Grantees the ability to meet and discuss their progress to date, and assess and receive assistance with any problems that have arisen.

3. ASPE will provide consultation and technical assistance in planning, and operating grant activities.

4. ASPE will assist in information exchange and the dissemination of reports to appropriate Federal, state and local entities.

Part III Application Preparation and Evaluation Criteria

This section contains information on the preparation of applications for submission under this announcement, on the forms necessary for submission, and on the evaluation criteria under which the applications will be reviewed. Potential applicants should read this section carefully in conjunction with the information provided above. The application must contain the required Federal forms, title page, table of contents, and the sections

listed below. All pages of the narrative should be numbered.

The application should include the following elements:

1. *Abstract:* A one page summary of the proposed project.

2. *Goals and objective of the project:* An overview that describes (1) the project, (2) the specific research questions to be investigated, (3) proposed accomplishments, and (4) knowledge and information to be gained from the project by the applicant, the government, and the research community. If the applicant is also applying for a grant to study the outcomes of welfare reform on Food Stamp Program leavers through the Economic Research Service, U.S. Department of Agriculture, then the applicant should specify here how the two activities would be coordinated. If the planned project builds on any current project, the application should describe how funding under this announcement will enhance, not substitute for, current state or local efforts.

3. *Methodology and Design:* Provide a description and justification of how the proposed research project will be implemented, including methodologies, chosen approach, data sources, and a research plan consistent with a descriptive, tabular analysis. The proposed research plan should:

(a) Describe in detail how the applicant plans to define welfare leavers, families who apply for cash welfare but are never enrolled because of non-financial eligibility requirements or diversion programs, and/or families who appear to be eligible but are not enrolled.

(b) Identify how the proposed datasets and variables will be used by the Grantee to answer each of the research questions described in the proposal.

(c) Identify important questions/issues for which data currently are not available, and strategies for dealing with this lack of data when it pertains to the research questions in the proposal.

(d) Describe in detail the methodology the applicant will use to extract samples of all families who leave the TANF program, families who apply for cash welfare but are never enrolled because of non-financial eligibility requirements or diversion programs, and/or families who appear to be eligible but are not enrolled. Applicants are encouraged to use a full population sample, but at minimum, a successful application will use a scientifically acceptable probability sampling method in which every sampling unit in the population has a known, non-zero chance to be included in the sample and a sample size large enough to make statistically reliable comparisons between planned subgroups.

(e) If administrative data-linking is planned, describe the criteria for the selection of existing data sets, as well as the methods used to clean, standardize and link the case level data from the different sources. Applicants should discuss thoroughly how they intend to match case records from different data sources, and what internal validity checks will ensure the accuracy of the matches. The architecture for the resulting data set should also be discussed in detail.

(f) If survey data collection is planned, identify and describe the methodology used to gather survey data. In particular, identify the sampling plan, the survey mode (e.g. telephone, in-person, mail), and the steps that will be taken to address any biases inherent in each. This should include steps planned to ensure a high response rate, such as a mixed mode design, multiple attempts to contact sample members, or respondent payments. Because of the importance of a high response rate in ensuring reliability, these procedures will be an important part of the evaluation of proposals.

(g) If qualitative research or focus groups are planned, the application should include a complete plan for data collection procedures and analysis, including the planned composition of groups, planned discussion topics or facilitator's questions, a plan for summarizing and organizing the results, and what this part of the project is expected to add to the interim and final reports. The application should demonstrate a familiarity with the difficulties and potential biases of this approach, and plans to avoid or resolve them.

(h) Identify the methodology the Grantee will use to analyze the data and organize the interim and final reports. Complex data analysis is neither expected nor preferred. Simple tabular analysis and descriptive statistics are appropriate. The description should include subgroup analyses planned, report organization and proposed tabulations, including table shells illustrating how the results will be presented.

To the extent that the analysis uses data on individuals from multiple, separate sources, such as administrative databases from several State agencies, the proposal should discuss measures taken to maintain confidentiality, as well as demonstrate that the Grantee has obtained authorized access to those data sources. The preferred form of proof is a signed interagency agreement with each of the relevant agencies/departments. Though not preferable, letters of support from the appropriate agencies are acceptable, provided that the letter clearly states that the proposing agency has the authorization to access and link all necessary data. Applicants must assure that the collected data will only be used for management and research purposes, and that all identifying information will be kept completely confidential, and should present the methods that will be used to ensure confidentiality of records and information once data are made available for research purposes.

4. *Experience, capacity, qualifications, and use of staff:* Briefly describe the applicant's organizational capabilities and experience in conducting pertinent research projects. If the proposal involves linking administrative databases from multiple programs the proposal should detail the applicant's experience in conducting relevant projects using linked administrative program data or identify key subcontractors with such experience. If the proposal involves survey work, the proposal should describe the applicant's experience in conducting relevant surveys or identify key subcontractors with such experience. Similarly, if the proposal involves qualitative data collection or analysis, the experience of the applicant or key subcontractors with this type of research and with these populations must be described in detail. If the applicant plans to contract for any of the work (e.g. data-linking, survey design or administration, qualitative analysis), and the contractors have not been retained, describe the process by which they will be selected. Identify the key staff who are expected to carry out the project and provide a résumé or curriculum vitae for each person. Provide a discussion of how key staff will contribute to the success of the project, including the percentage of their time which will be devoted to the project.

Applicants should demonstrate access to computer hardware and software for storing and analyzing the data necessary to complete this project.

5. *Work plan:* A work plan should be included which describes the start and end dates of the project, the responsibilities of each of the key staff, and a time line which indicates the sequence of tasks necessary for the completion of the project. It should identify other time commitments of key staff members such as other projects and/or teaching or managerial responsibilities in absolute and percentage terms. The work plan should

include a discussion of plans for dissemination of the results of the study, e.g., articles in journals and presentations to the State legislature or at conferences. It should also discuss in detail how resulting data and analysis will be made available to qualified researchers and to ASPE. As noted above, ASPE prefers that the data be edited as appropriate for confidentiality and issued as a public-use data file. If the applicant believes that provision of a public-use file would be impossible, the application should explain why and should fully articulate how the applicant will make the data available to qualified researchers and to ASPE.

6. *Budget:* Applicants must submit a request for federal funds using Standard Form 424A and include a detailed breakdown of all Federal line items. A narrative explanation of the budget should be included which explains fund usage in more detail. The applicant should clearly state how the funds associated with this announcement will be used and describe the extent to which these funds will be used for purposes that would not otherwise be incorporated within the project. The applicant should also document the level of funding from other sources, if any, and describe how these funds will be utilized.

All applicants must budget for two trips to the Washington, D.C., area, for at least two people on each trip. As part of this grant, ASPE will schedule one to two meetings for all funded projects. The first meeting will be for planning purposes, where applicants will have the opportunity to meet, discuss their projects, and receive feedback from both the other Grantees and from ASPE staff and invited experts. This meeting will occur not more than 60 days after the proposals are funded. The second meeting will be approximately 6 to 8 months into the grant period, and will provide Grantees the ability to meet and discuss their progress to date, and assess and receive assistance with any problems that have arisen.

Optional PD&R supplement: Applicants who wish to be considered for the PD&R supplement should attach an appendix to the main proposal. The appendix must contain a proposal to analyze the experience of families assisted by the different HUD programs relative to families not assisted and relative to each other, using state agency files matched with the file provided by HUD. The supplementary proposal should identify the subsets of low-income families with children in the state that the applicant considers of greatest policy interest. The elements of this supplementary proposal should be the same as the elements of the main proposal, i.e., abstract; goals and objectives; methodology and design; experience, capacity, qualifications, and use of staff; work plan; and budget.

Review Process and Funding Information

Applications will be initially screened for compliance with the timeliness and completeness requirements. Three (3) copies of each application are required. One of these copies must be in an unbound format, suitable for copying. If only one of the copies is the original (i.e. carries the original signature and is accompanied by a cover letter) it should not be this copy.

A Federal panel will review and score all applications that are submitted by the deadline date and which meet the screening criteria (all information and documents as required by this Announcement.) The panel will review the applications using the evaluation criteria listed below to score each application. These review results will be the primary element used by the ASPE in making funding decisions. The Department reserves the option to discuss applications with other Federal or State staff, specialists, experts and the general public. Comments from these sources, along with those of the reviewers, will be kept from inappropriate disclosure and may be considered in making an award decision.

As a result of this competition, between 8 and 10 grants are expected to be made from funds appropriated for fiscal year 1998. Additional awards may be made depending on the policy relevance of proposals received and the available funding, including funds that may become available in FY99. The Department reserves the right to make fewer awards. The average grant is expected to be between $200,000 and $250,000.

After ASPE has decided to fund a proposal from a particular state, PD&R will decide whether to fund the optional proposal related to HUD-assisted families, if there is one. In making this determination, PD&R will use all of the criteria listed below except item 5 (ability to sustain project after funding).

Reports

As noted in the Grantee Responsibilities, three substantive reports are required under the grant. (1) A final work plan is due 30 days after the initial consultation meeting. (2) An interim report including initial results, if any, and a plan for any further data collection and analysis is due 90 days later. (3) A final report including all results and analysis is due before the end of the project.

In addition, Grantees shall provide concise quarterly progress reports. The specific format and content for these reports will be provided by the project officer.

State Single Point of Contact (E.O. No. 12372)

DHHS has determined that this program is not subject to Executive Order 12372, ''Intergovernmental Review of Federal Programs.'' Applicants are not required to seek intergovernmental review of their applications within the constraints of E.O. 12372.

Deadline for Submission of Applications

The closing date for submission of applications under this announcement is July 6, 1998. Hand-delivered applications will be accepted Monday through Friday, excluding Federal holidays during the working hours of 9:00 a.m. to 4:30 p.m. in the lobby of the Hubert H. Humphrey building located at 200 Independence Avenue, SW in Washington, D.C. When hand-delivering an application, call (202) 690–8794 from the lobby for pick up. A staff person will be available to receive applications. Application submissions may not be faxed or submitted electronically.

An application will be considered as meeting the deadline if it is either (1) received at, or hand-delivered to, the mailing address on or before July 6, 1998, or (2) postmarked before midnight five days prior to July 6, 1998 and received in time to be considered during the competitive review process (within two weeks of the deadline date).

When mailing applications, applicants are strongly advised to obtain a legibly dated receipt from a commercial carrier (such as UPS, Federal Express, etc.) or from the U.S. Postal Service as proof of mailing by the deadline date. If there is a question as to when an application was mailed, applicants will be asked to provide proof of mailing by the deadline date. When proof is not provided, an application will not be considered for funding. Private metered postmarks are not acceptable as proof of timely mailing.

Applications which do not meet the deadline will be considered late applications and will not be considered or reviewed in the current competition. DHHS will send a letter to this effect to each late applicant.

DHHS reserves the right to extend the deadline for all proposals due to natural disasters, such as floods, hurricanes, or

earthquakes; or if there is a widespread disruption of the mail; or if DHHS determines a deadline extension to be in the best interest of the government. However, DHHS will not waive or extend the deadline for any applicant unless the deadline is waived or extended for all applicants.

Application Forms

Copies of applications should be requested from and submitted to: Grants Officer, Office of the Assistant Secretary for Planning and Evaluation, Department of Health and Human Services, 200 Independence Avenue, SW., Room 405F, Hubert H. Humphrey Building, Washington, D.C. 20201, Telephone: (202) 690–8794. Requests for forms and questions (administrative and technical) will be accepted and responded to up to 10 working days prior to closing date of receipt of applications.

Copies of this program announcement and many of the required forms may also be obtained electronically at the ASPE World Wide Web Page *http://aspe.os.dhhs.gov*. You may fax your request to (202) 690–6518 to the attention of the Grants Officer. Application submissions may not be faxed or sent electronically.

The printed **Federal Register** notice is the only official program announcement. Although reasonable efforts are taken to assure that the files on the ASPE World Wide Web Page containing electronic copies of this Program Announcement are accurate and complete, they are provided for information only. The applicant bears sole responsibility to assure that the copy downloaded and/or printed from any other source is accurate and complete.

Also see section entitled ''Components of a Complete Application.'' All of these documents must accompany the application package.

Length of Application

Applications should be as brief as possible but should assure successful communication of the applicant's proposal to the reviewers. In no case shall an application for the primary ASPE grant (excluding the resumes, appendices and other appropriate attachments) be longer than 30 single spaced pages. Applications should be neither unduly elaborate nor contain voluminous supporting documentation. Applications for the supplemental PD&R grant should be no longer than 12 single-spaced pages, and should make frequent reference to the primary application for purposes of brevity.

Selection Process and Evaluation Criteria

Selection of the successful applicant will be based on the technical and financial criteria described in this announcement. Reviewers will determine the strengths and weaknesses of each application in terms of the evaluation criteria listed below, provide comments and assign numerical scores. The review panel will prepare a summary of all applicant scores and strengths/weaknesses and recommendations and submit it to the ASPE for final decisions on the award.

The point value following each criterion heading indicates the maximum numerical weight that each section will be given in the review process. An unacceptable rating on any individual criterion may render the application unacceptable. Consequently, applicants should take care to ensure that all criteria are fully addressed in the applications. Applications will be reviewed as follows:

1. *Goals, Objectives, and Potential Usefulness of the Analyses* (25 points). The potential usefulness of the objectives and how the anticipated results of the proposed project will advance policy knowledge and development. If the proposed project builds on previous work the application should explain how. Applications will be judged on the quality and policy relevance of the proposed questions. Applications which do not address employment and earnings factors will not be considered fundable.

2. *Quality and Soundness of Methodology and Design* (30 points). The appropriateness, soundness, and cost-effectiveness of the methodology, including the research design, selection of existing data sets, data gathering procedures, statistical techniques, and analytical strategies. Richness of policy relevant data will be an important scoring factor in this criterion.

If administrative data-linking is planned, a critical scoring element will be the proposal's discussion of the methods used to clean, standardize and link the case level data from the different sources, including any proposed links between administrative data and surveys. Applicants should discuss thoroughly how they intend to match case records from different data sources, and what internal validity checks will ensure the accuracy of the matches. The architecture for the resulting data set should also be discussed thoroughly. Other design considerations include whether the agency applying has already obtained authorization to obtain and use data from the state or local agencies whose data would be linked, and how confidentiality of the records and information will be ensured. If applicants are unable to ensure the security of information included in the project, then it is highly unlikely that they will receive funding.

If survey data collection is planned, reviewers will evaluate the methodology proposed to gather survey data. In particular, reviewers will evaluate the sampling plan, the survey mode (e.g. telephone, in-person, mail), and the steps that will be taken to address any biases inherent in each. This will include evaluating steps planned to ensure a high response rate, such as a mixed mode design, multiple attempts to contact sample members, or respondent payments. Because of the importance of a high response rate in ensuring reliability, these procedures will be an important part of the evaluation of proposals containing surveys.

If qualitative research or focus groups are planned, reviewers will evaluate the plan for data collection and analysis, including the planned composition of groups, planned discussion topics or facilitator's questions, a plan for summarizing and organizing the results, and what this part of the project is expected to add to the interim and final reports. The extent to which the application demonstrates a familiarity with the difficulties and potential biases of this approach, and plans to avoid or resolve them, will also be a scoring factor.

3. *Qualifications of Personnel and Organizational Capability*. (20 points). The qualifications of the project personnel for conducting the proposed research as evidenced by professional training and experience, and the capacity of the organization to provide the infrastructure and support necessary for the project. Reviewers will evaluate the applicant's principal investigator and staff on research experience and demonstrated research skills. Proposals which involve linking of administrative data and assembling of large databases will also be evaluated in terms of the experience of the applicant's or subcontractor's experience with such linking efforts. Proposals which involve survey work will be evaluated in terms of the applicant's or subcontractor's's experience in conducting relevant surveys. Similarly, if the proposal involves qualitative data collection or analysis, it will be evaluated in terms of the experience of the applicant or key subcontractors with this type of research and with these populations. If the applicant plans to contract for any of the

work (e.g. data-linking, survey design or administration, qualitative analysis), and the contractors have not been retained, reviewers will consider the process by which they will be selected. Ratings may consider references on prior research projects. Principal investigator and staff time commitments also will be a factor in the evaluation. Reviewers will rate the applicant's pledge and ability to work in collaboration with other scholars or organizations in search of similar goals. Reviewers also will evaluate the applicant's demonstrated capacity to work with a range of government agencies.

4. *Ability of the Work Plan and Budget to Successfully Achieve the Project's Objectives.* (20 points). Reviewers will examine if the work plan and budget are reasonable and sufficient to ensure timely implementation and completion of the study and whether the application demonstrates an adequate level of understanding by the applicant of the practical problems of conducting such a project. Adherence to the work plan is particularly important because it is necessary in order to produce results in the time frame desired; demonstration of an applicant's ability to meet the schedule will be an important part of this criterion. Reviewers will also examine the use of any additional funding and the role that funds provided under this announcement will play in the overall project. The proposed strategy for dissemination of analysis results and data will also be considered. It should also discuss in detail how resulting data will be made available to qualified researchers and to ASPE. As noted above, ASPE prefers that the data be edited as appropriate for confidentiality and issued as a public-use data file. If the applicant believes that provision of a public-use file would be impossible, the application should explain why and should fully articulate how the applicant will make the data available to qualified researchers and to ASPE.

5. *Ability to Sustain Project After Funding* (5 points). Reviewers will consider whether the proposal adequately addresses the following questions: How will the tracking of outcomes for these populations become an institutionalized function within the agency once the grant funding expires? Where will the newly created data set reside? What agency(ies) will have responsibility for and jurisdiction over the resulting data? What are the sources of financial and staff support for maintaining the database? How will the data be used for future policy planning, research and evaluation?

Disposition of Applications

1. *Approval, disapproval, or deferral.* On the basis of the review of the application, the Assistant Secretary will either (a) approve the application as a whole or in part; (b) disapprove the application; or (c) defer action on the application for such reasons as lack of funds or a need for further review.

2. *Notification of disposition.* The Assistant Secretary for Planning and Evaluation will notify the applicants of the disposition of their applications. If approved, a signed notification of the award will be sent to the business office named in the ASPE checklist.

3. *The Assistant Secretary's Discretion.* Nothing in this announcement should be construed as to obligate the Assistant Secretary for Planning and Evaluation to make any awards whatsoever. Awards and the distribution of awards among the priority areas are contingent on the needs of the Department at any point in time and the quality of the applications which are received.

The Catalog of Federal Domestic Assistance number is 93–239.

Components of a Complete Application

A complete application consists of the following items in this order:

1. Application for Federal Assistance (Standard Form 424);
2. Budget Information—Non-construction Programs (Standard Form 424A);
3. Assurances—Non-construction Programs (Standard From 424B);
4. Table of Contents;
5. Budget Justification for Section B Budget Categories;
6. Proof of Non-profit Status, if appropriate;
7. Copy of the applicant's Approved Indirect Cost Rate Agreement, if necessary;
8. Project Narrative Statement, organized in five sections addressing the following topics:
(a) Abstract,
(b) Goals, Objectives and Usefulness of the Project,
(c) Methodology and design,
(d) Background of the Personnel and Organizational Capabilities and
(e) Work plan (timetable);
9. Any appendices or attachments;
10. Certification Regarding Drug-Free Workplace;
11. Certification Regarding Debarment, Suspension, or other Responsibility Matters;
12. Certification and, if necessary, Disclosure Regarding Lobbying;
13. Supplement to Section II—Key Personnel;
14. Application for Federal Assistance Checklist.

Dated: May 13, 1998.

Margaret A. Hamburg,

Assistant Secretary for Planning and Evaluation.

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BILLING CODE 4151–04–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

[Program Announcement 98090]

Evaluation of Health-Care Worker Glove Protection During Surgery and Effects of Storage, Chemicals, Disinfectants on Glove Integrity; Availability of Funds

A. Purpose

The Centers for Disease Control and Prevention (CDC) announces the availability of fiscal year (FY) 1998 funds for a cooperative agreement program for the evaluation of health-care worker glove protection during surgery and the effects of storage, chemicals, and disinfectants on glove integrity. This program addresses the ''Healthy People 2000'' priority area(s) area of Occupational Safety and Health.

The purpose of the program is to evaluate gloves (non-latex polymer e.g., nitrile, vs natural latex rubber (NLR)) in surgery; (veterinary surgery is suggested as a surrogate for human surgery) and to evaluate the effects of storage conditions, disinfectants, detergents, other chemicals, and blood and body fat on vinyl, NLR, and non-latex polymer examination gloves and latex and non-latex polymer surgical gloves.

B. Eligible Applicants

Applications may be submitted by public and private nonprofit and for-profit organizations and by governments and their agencies; that is, universities, colleges, research institutions, hospitals, other public and private nonprofit and for-profit organizations, State and local governments or their bona fide agents.

Note: Pub. L. 104–65 states that an organization described in section 501(c)(4) of the Internal Revenue Code of 1986 that engages in lobbying activities is not eligible to receive Federal funds constituting an award, grant, cooperative agreement, contract, loan, or any other form.

C. Availability of Funds

Approximately $600,000 is available in FY 1998 to fund approximately three awards, preferably at least one in each category (A and B). It is expected that

the average award will be $200,000, ranging from $150,000 to $300,000. It is expected that the awards will begin on or about September 1, 1998, and will be made for a 12-month budget period within a project period of up to two 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: The applicant should allocate funds for at least one annual CDC/NIOSH directed meeting.

Programmatic Interest

The applicant may address either or both of the components identified below:

A. Evaluate the degradation characteristics of examination and surgical gloves.

B. Evaluation of the similarities and differences of NLR and non-latex gloves during surgery including protection of wearer from needlestick and other sharp injuries (puncture and tear resistance) and worker acceptance.

D. Cooperative Agreement Requirements

In conducting activities to achieve the purpose of this program, the recipient will be responsible for activities under A. (Recipient Activities), and CDC/NIOSH will be responsible for the activities listed under B. (CDC/NIOSH Activities).

A. Recipient Activities

1. Develop, implement, and evaluate a study protocol.

2. Provide statistical analysis of the data.

3. Disseminate study results to the scientific community.

4. Collaborate with CDC/NIOSH on these activities and the activities listed below.

B. CDC/NIOSH Activities

1. Providing scientific and technical collaboration including study design and protocol development, and data analysis.

2. Monitor and evaluate scientific and operational accomplishments of the project through site visits, telephone calls, and review of technical reports and interim data analysis.

3. Collaborate with awardee(s) on data analysis, and interpretation of findings.

4. Review the results of the study and collabroate, where appropriate, in the preparation and publication of results in peer-reviewed journals.

E. Application Content

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 double-spaced pages, printed on one side, with one inch margins, and unreduced font.

F. Submission and Deadline

Submit the original and five copies of PHS–398 (OMB Number 0925–0001)(adhere to the instructions on the Errata Instruction Sheet for PHS 398). Forms are in the application kit. On or before July 23, 1998, submit the application to: Victoria Sepe, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Announcement 98090, Centers for Disease Control and Prevention (CDC), Room 300, 255 East Paces Ferry Road, NE., M/S E–13, Atlanta, Georgia 30305–2209.

If your application does not arrive in time for submission to the independent review group, it will not be considered in the current competition unless you can provide proof that you mailed it on or before the deadline (i.e., receipt from U.S. Postal Service or a commercial carrier; private metered postmarks are not acceptable).

G. Evaluation Criteria

Each application will be evaluated individually against the following criteria by an independent review group appointed by CDC.

1. Understanding of the Problem (15%)

Responsiveness to the objective of the cooperative agreement including: (a) Applicant's understanding of the general objectives of the proposed cooperative agreement, and (b) evidence of ability to design an effective evaluation study.

2. Experience (15%)

The extent to which the applicant's prior work and experience in developing and performing laboratory assay (Part A) and/or surgical assays (Part B).

3. Goals, Objectives and Methods (35%)

The extent to which the proposed goals and objectives are clearly stated, time-phased, and measurable. The extent to which the methods are sufficiently detailed to allow assessment of whether the objectives can be achieved for the budget period. Clearly state the evaluation method for evaluating the accomplishments. The extent to which a qualified plan is proposed that will help achieve the goals stated in the proposal.

4. Facilities and Resources (10%)

The adequacy of the applicant's facilities, equipment, and other resources available for performance of this project. The proposal should include a commitment from the participating institution, as evidenced by a written agreement. For applicants applying to conduct the evaluation of glove performance in surgery, the proposal should include a commitment, as evidenced by a written agreement, from the chief of surgery, head of operating room nursing, and other directors with jurisdiction over the surgical suite, when such exist at the applicant's institution.

5. Project Management and Staffing Plan (15%)

The extent to which the management staff and their working partners are clearly described, appropriately assigned, and have pertinent skills and experiences. The extent to which the applicant proposes to involve appropriate personnel who have the needed qualifications to implement the proposed plan. The extent to which the applicant has the capacity to design, implement, and evaluate the proposed intervention program.

6. Collaboration (10%)

The extent to which all partners are clearly described and their qualifications and the extent to which their intentions to participate are explicitly stated. The extent to which the applicant provides proof of support (e.g., letters of support and/or memoranda of understanding) for proposed activities. Evidence or a statement should be provided that these funds do not duplicate already funded components of ongoing projects.

7. Budget Justification (Not Scored)

The budget will be evaluated to the extent that it is reasonable, clearly justified, and consistent with the intended use of funds.

8. Human Subjects (Not Scored)

If human subjects will be involved, how will they be protected, i.e., describe the review process which will govern their participation. The applicant must demonstrate that they have met the CDC Policy requirements regarding the inclusion of women, ethnic, and racial groups in the proposed research. This includes: (a) The proposed plan for the inclusion of both sexes and racial and

ethnic minority populations for appropriate representation; (b) The proposed justification when representation is limited or absent; (c) A statement as to whether the design of the study is adequate to measure differences when warranted; (d) A statement as to whether the plans for recruitment and outreach for study participants include the process of establishing partnerships with community(ies) and recognition of mutual benefits.

9. Animal Subjects (Not Scored)

If the proposed project involves research on animal subjects, the applicant must comply with the ''PHS Policy on Humane Care and Use of Laboratory Animals by Awardee Institutions.'' An applicant organization proposing to use vertebrate animals in PHS-supported activities must file an Animal Welfare Assurance with the Office of Protection from Research Risks at the National Institutes of Health.

H. Other Requirements

Technical Reporting Requirements

Provide CDC with original plus two copies of:

1. Semi-annual progress reports including a brief program description and a listing of program goals and objectives accompanied by a comparison of the actual accomplishments related to the goals and objectives established for the period;

2. financial status report, no more than 90 days after the end of the budget period; and

3. final financial and performance reports, no more than 90 days after the end of the project period.

Send all reports to: Victoria Sepe, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention (CDC), Room 300, 255 East Paces Ferry Road, NE., M/S E–13, Atlanta, GA 30305–2209.

The following additional requirements are applicable to this program. For a complete description of each, see Addendum I (included in the application package).

AR98–1 Human Subjects Requirements
AR98–2 Requirements for Inclusion of Women and Racial and Ethnic Minorities in Research
AR98–3 Animal Subjects Requirements
AR98–9 Paperwork Reduction Act Requirements
AR98–10 Smoke-Free Workplace Requirements
AR98–11 Healthy People 2000
AR98–12 Lobbying Restrictions

I. Authority and Catalog of Federal Domestic Assistance Number

This program is authorized under Sections 20(a) and 22(e)(7) of the Occupational Safety and Health Act of 1970 (29 U.S.C. 669(a) and 671(e)(7)). The Catalog of Federal Domestic Assistance number is 93.262 for the National Institute for Occupational Safety and Health.

J. Where To Obtain Additional Information

To receive additional written information call 1–888–GRANTS4. You will be asked to leave your name, address, and phone number and will need to refer to NIOSH Announcement 98090. You will receive a complete program description, information on application procedures, and application forms. CDC will not send application kits by facsimile or express mail. PLEASE REFER TO NIOSH ANNOUNCEMENT NUMBER 98090 WHEN REQUESTING INFORMATION AND SUBMITTING AN APPLICATION.

If you have questions after reviewing the contents of all the documents, business management technical assistance may be obtained by contacting: Victoria Sepe, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Announcement 98090, Centers for Disease Control and Prevention (CDC), Room 300, 255 East Paces Ferry Road, NE., M/S E–13, Atlanta, GA 30305–2209, telephone (404) 842–6804, Email address: vxw1@cdc.gov.

See also the CDC home page on the Internet: http://www.cdc.gov.

For program technical assistance contact:

Scott Deitchman, M.D., telephone (404) 639–1534, Email sed2@cdc.gov

or

Robert Mullan, M.D., telephone (404) 639–1533, Email rjm1@cdc.gov, National Institute for Occupational Safety and Health, Centers for Disease Control and Prevention (CDC), HIV Activity, 1600 Clifton Rd., NE., Mailstop D–40, Atlanta, GA 30333.

National Occupational Research Agenda (NORA): CDC, NIOSH is committed to the program priorities developed by NORA. Copies of the publication, ''The National Occupational Research Agenda'' may be obtained from The National Institute of Occupational Safety and Health, Publications Office, 4676 Columbia Parkway, Cincinnati, OH 45226–1998 or phone 1–800–356–4674, and is available through the NIOSH Home Page, ''http://www.cdc.gov/niosh/nora.html'' .

Dated: May 14, 1998.

Diane D. Porter,

Acting Director, National Institute For Occupational Safety and Health, Centers for Disease Control and Prevention (CDC).

[FR Doc. 98–13516 Filed 5–20–98; 8:45 am]

BILLING CODE 4163–19–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

[Announcement Number 98067]

Cooperative Agreement for a Suicide Prevention Research Center; Availability of Funds

A. Purpose

The Centers for Disease Control and Prevention (CDC) announces the availability of fiscal year 1998 cooperative agreement funds to establish a Suicide Prevention Research Center. This program addresses the Healthy People 2000 priority area of Violent and Abusive Behavior.

The purposes are:

1. To support Suicide Prevention Research Center (SPRC) which represent CDC's largest national extramural investment in suicide prevention research and training, intervention development, and evaluation;

2. To integrate collectively, in the context of a national program, the disciplines of epidemiology, medicine, biostatistics, public health, and behavioral and social sciences in order to prevent injuries from suicidal behavior more effectively;

3. To identify and evaluate current and new interventions for the prevention and control of suicide-related injuries;

4. To bring the knowledge and expertise of SPRC to bear on the development and improvement of effective public and private sector programs for suicide prevention and control; and

5. To facilitate suicide prevention efforts supported by various governmental and non-governmental agencies within a geographic region.

For additional information please see Addendum 2, Background and Definitions (included in the application package).

B. Eligible Applicants

Applications may be submitted by public and private nonprofit

organizations and by governments and their agencies; that is, universities, colleges, research institutions, hospitals, other public and private nonprofit organizations, State and local governments or their bona fide agents, and federally recognized Indian tribal governments, Indian tribes, or Indian tribal organizations.

C. Availability of Funds

Approximately $500,000 is expected to be available in fiscal year (FY) 1998 to fund one new center project. It is expected that the award will begin on or around September 30, 1998, and will be made for a 12 month budget period, not to exceed a project period of three years. Funding estimates may vary and are subject to change.

Continuation awards within the project period will be made on the basis of satisfactory progress and the availability of funds.

D. Program Requirements

The following are applicant requirements:

1. Applicant must demonstrate expertise in some form of suicide prevention research.

2. Applicant must provide a director (Principal Investigator) who has specific authority and responsibility to carry out the project.

E. Cooperative Agreement Activities

In conducting activities to achieve the purpose of this program, the recipient will be responsible for the activities under 1. (Recipient Activities), and CDC will be responsible for activities listed under 2. (CDC Activities).

1. Recipient Activities:

a. Conduct, evaluate, and publish suicide prevention research.

b. Design, implement, and evaluate suicide prevention programs.

c. Collaborate with outside agencies and other entities which will allow for implementation of any proposed intervention activities.

d. Collaborate with at least one National organization that has suicide prevention as its major objective and whose members are actively engaged in suicide prevention activities.

e. Develop a curricula and graduate training programs in disciplines relevant to suicide prevention (e.g., epidemiology or behavioral sciences).

f. Disseminate injury control research findings, translate them into interventions, and evaluate their effectiveness.

2. CDC Activities:

a. Collaborate in establishing research and evaluation priorities, and defining the target populations.

b. Provide technical assistance.

F. Application Content

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.

1. The narrative should be no more than 30 double-spaced pages, printed on one side, with one inch margins, and unreduced font.

2. Applications must be organized as follows: Applications for support of a SPRC should follow the PHS Form 398 (Revised 9/91, OMB Control Number 0925–0001) format and should include the following information:

a. Face page.

b. Description (abstract) and personnel.

c. Table of contents.

d. Detailed budget for the initial budget period: The budget should reflect the composite figures for the grant as well as breakdown budgets for individual projects within the grant.

e. Budget for entire proposed project period including budgets pertaining to consortium/contractual arrangements.

f. Core Faculty: Biographical sketches of key personnel, consultants, and collaborators, beginning with the Principal Investigator and core faculty.

g. Organizational collaboration: The applicant must describe a collaborative relationship with at least one National organization that has suicide prevention as its major objective and whose members are actively engaged in suicide prevention activities. The collaborating organization should be described in terms that demonstrate how collaboration with the applicant will strengthen the proposed SPRC. Roles and activities for collaborating organizations must be clearly specified in relation to the SPRCs goals and objectives. Evidence of relationships should be documented through letters that detail commitments and a clear statement of the role, activities, and participating personnel of each organization.

h. Research and prevention plan including:

1. The proposed activities should be clearly described in terms of need, scientific basis, expected interactions, and anticipated outcomes, including the expected effect on injury morbidity and mortality. In selecting the theme, applicants should consider the findings in *Injury In America* and the *Year 2000 Objectives for the Nation*.

2. A research plan (design and methods) including hypothesis and expected outcome, value to field, and specific, measurable, and time-framed objectives consistent with the proposed theme and activities for each project within the proposed grant. The applicant must demonstrate that they have met the CDC/ATSDR policy requirements regarding the inclusion of women, ethnic, and racial groups in the proposed projects. This includes:

a. The proposed plan for the inclusion of both sexes and racial and ethnic minority populations for appropriate representation;

b. The proposed justification when representation is limited or absent;

c. A statement as to whether the design of the study is adequate to measure differences when warranted; and

d. A statement as to whether the plans for recruitment and outreach for study participants include the process of establishing partnerships with community(ies) and recognition of mutual benefits.

Human Subjects: If the proposed research involves obtaining data through intervention or interaction with an individual(s) or identifiable private information then the applicant must provide background information on the precautions that will be put in place to protect human subjects.

3. A description of the core faculty and its role in implementing and evaluating the proposed programs.

4. Charts showing the proposed organizational structure of the SPRC and its relationship to the broader institution of which it is a part, and, where applicable, to affiliate institutions or collaborating organizations. These charts should clearly detail the lines of authority as they relate to the center or the project, both structurally and operationally. SPRC's should report to an appropriate organizational level (e.g., dean of a school, vice president of a university, or commissioner of health), demonstrating strong institution-wide support of SPRC activity and ensuring oversight of the process of interdisciplinary activity.

5. Documentation of the involved public health agencies and other public and private sector entities to be involved in the proposed program, including letters that detail commitments of support and a clear statement of the role, activities, and participating personnel of each agency or entity.

G. Submission and Deadline

Submit the original and five copies of PHS Form 398 (Revised 9/91, OMB

Control Number 0925–0001). Please adhere to the instructions on the Errata Instruction Sheet for PHS Form 398. Forms are in the application kit.

On or before July 21, 1998, submit to:

Lisa T. Garbarino, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Announcement Number 98067, Centers for Disease Control and Prevention (CDC), 255 East Paces Ferry Road, NE., Mailstop E–13, Room 300, Atlanta, Georgia 30305–2209.

If your application does not arrive in time for submission to the independent review group, it will not be considered in the current competition unless you can provide proof that you mailed it on or before the deadline (i.e., receipt from U.S. Postal Service or a commercial carrier; private metered postmarks are not acceptable).

H. Evaluation Criteria

Each application will be evaluated individually against the following criteria by an independent reviewer group appointed by CDC. Applicants will be evaluated according to the following criteria (Maximum of 100 total points):

1. Core faculty, staff, and organizational capacity (30 points)

a. *Core faculty:* Qualifications, experience, and/or ability of core faculty in conducting research relevant to suicide prevention. Faculty history and experience in receiving research support from competitive sources of funding.

b. *Staffing plan:* Qualifications, adequacy, and appropriateness of personnel to accomplish the proposed activities.

c. *Organizational capacity:* Existence and availability of organizational resources and support for achieving research and prevention goals.

2. Organizational collaboration (30 points)

a. The extent to which the collaborative relationship (joint activities and access to the collaborative organization's membership for promoting prevention activities) will be considered and will strengthen the proposed SPRC.

b. The extent to which the collaborating organization is a National organization that has suicide prevention as its major objective and whose members are actively engaged in suicide prevention activities.

3. Research and prevention plan (40 points)

a. The extent to which suicide is a public health problem in the State(s) or region to be served by the SPRC.

b. The extent to which the applicant plans to provide consultation, technical assistance, and training to public and private agencies and institutions in the area of suicide prevention.

c. The extent to which the research plan is responsive to needed research in the area of suicide prevention.

d. If human subjects are involved, how they will be protected, i.e., describe the review process which will govern their participation. The applicant must demonstrate that they have met the CDC/ATSDR policy requirements regarding the inclusion of women, ethnic, and racial groups in the proposed projects. This includes:

1. The proposed plan for the inclusion of both sexes and racial and ethnic minority populations for appropriate representation;

2. The proposed justification when representation is limited or absent;

3. A statement as to whether the design of the study is adequate to measure differences when warranted; and

4. A statement as to whether the plans for recruitment and outreach for study participants include the process of establishing partnerships with community(ies) and recognition of mutual benefits.

4. Budget (not scored)

Soundness of the proposed budget in terms of adequacy of resources and their allocation.

I. Other Requirements

Technical Reporting Requirements

Provide CDC with original plus two copies of:

a. Quarterly progress reports;

b. Financial status report, no more than 90 days after the end of the budget period; and

c. Final financial report and performance report, no more than 90 days after the end of the project period.

Send all reports to: Lisa T. Gabarino, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention (CDC), 255 East Paces Ferry Road, NE., Mailstop E–13, Room 300, Atlanta, Georgia 30305–2209.

The following additional requirements are applicable to this program. For a complete description of each, see Addendum 1 (included in the application kit).

AR98–1 Human Subjects Requirements

AR98–2 Requirements for Inclusion of Women and Racial and Ethnic Minorities in Research

AR98–7 Executive Order 12372 Review

AR98–9 Paperwork Reduction Act Requirements

AR98–10 Smoke-Free Workplace Requirements

AR98–11 Healthy People 2000

AR98–12 Lobbying Restrictions

AR98–13 Prohibition on Use of CDC Funds for Certain Gun Control Activities

J. Authority and Catalog of Federal Domestic Assistance Number

This program announcement is authorized under sections 301, 317, and 391–394A (42 U.S.C. 241, 247b, and 280b–280b–3) of the Public Health Service Act as amended. The Catalog of Federal Domestic Assistance number is 93.136.

K. Where To Obtain Additional Information:

To receive additional written information call 1–888–GRANTS4 (1–888–472–6874). You will be asked to leave your name, organization, address, and phone number and will need Announcement Number 98067.

All application procedures and guidelines are contained within that package or can be found on the CDC Homepage. The address for the CDC Homepage is (http://www.cdc.gov). For your convenience, you may be able to retrieve a copy of the PHS Form 398 from (http://www.nih.gov.grants/funding).

Business management technical assistance, contact: Lisa T. Garbarino, Grants Management Specialist, Grants Management Branch, Procurement and Grants Office, Centers for Disease Control and Prevention (CDC), 255 East Paces Ferry Road, NE., Mailstop E–13, Room 300, Atlanta, Georgia 30305–2209, Telephone (404) 842–6796, E-mail address lgt1@cdc.gov.

For program technical assistance, contact: Timothy Thornton, Division of Violence Prevention, National Center for Injury Prevention and Control (NCIPC), Centers for Disease Control and Prevention (CDC), 4770 Buford Highway, NE., Mailstop K–60, Atlanta, Georgia 30341–3724, Telephone (770) 488–4389, E-mail address tnt1@cdc.gov.

Dated: May 15, 1998.

Joseph R. Carter,

Acting Associate Director for Management and Operations, Centers for Disease Control and Prevention (CDC).

[FR Doc. 98–13545 Filed 5–20–98; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

CDC Advisory Committee on HIV and STD Prevention; Meeting

In accordance with section l0(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: CDC Advisory Committee on HIV and STD Prevention.

Times and Dates:

8:30 a.m.–5 p.m., June 16, 1998.

8:30 a.m.–12 p.m., June 17, 1998.

Place: Corporate Square Office Park, Corporate Square Boulevard, Building 11, Room 1413, Atlanta, Georgia 30329.

Status: Open to the public, limited only by the space available. The meeting room will accommodate approximately 100 people.

Purpose: This Committee is charged with advising the Director, CDC, regarding objectives, strategies, and priorities for HIV and STD prevention efforts including maintaining surveillance of HIV infection, AIDS, and STDs, the epidemiologic and laboratory study of HIV/AIDS and STDs, information/education and risk reduction activities designed to prevent the spread of HIV and STDs, and other preventive measures that become available.

Matters to be Discussed: Agenda items include issues pertaining to syphilis elimination; HIV prevention activities in the rural U.S.; and priority prevention services for HIV-infected persons. Agenda items are subject to change as priorities dictate.

Contact Person for More Information: Beth Wolfe, Committee Management Analyst, National Center for HIV, STD, and TB Prevention, 1600 Clifton Road, NE, Mailstop E–07, Atlanta, Georgia 30333, telephone (404) 639–8008.

Dated: May 15, 1998.

Nancy C. Hirsch,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention (CDC).

[FR Doc. 98–13550 Filed 5–20–98; 8:45 am]

BILLING CODE 4163–18–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Disease Control and Prevention

Mine Health Research Advisory Committee 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: Mine Health Research Advisory Committee (MHRAC).

Time and Date: 9 a.m.–4 p.m., June 26, 1998.

Place: The Washington Court Hotel, Montpelier Room, 525 New Jersey Avenue, NW., Washington, DC 20001.

Status: Open to the public, limited only by space available. The meeting room accommodates approximately 50 people.

Purpose: The Committee is charged with advising the Secretary; the Assistant Secretary for Health; the Director, Centers for Disease Control and Prevention; and the Director, National Institute for Occupational Safety and Health, Centers for Disease Control and Prevention, on priorities in mine safety and health research, including grants and contracts for such research, 30 U.S.C. 812(b)(2), ection 102(b)(2).

Matters to be Discussed: The agenda will include MHRAC history; funding; the Federal Advisory Committee Act; Research Program Transition: FY 1996–FY 1998; FY 1997 and FY 1998 Accomplishments in Disaster Prevention and Response; and Mining Research Gaps and Emerging Themes.

Agenda items are subject to change as priorities dictate.

Contact Person for More Information: Larry Grayson, Ph.D., Executive Secretary, MHRAC, NIOSH, CDC, 200 Independence Avenue, SW., Room 715–H, Humphrey Building, Washington, DC 20201, telephone (202) 401–2192, fax (202) 260–4464.

Dated: May 15, 1998.

Nancy C. Hirsch,

Acting Director, Management Analysis and Services Office, Centers for Disease Control and Prevention (CDC).

[FR Doc. 98–13549 Filed 5–20–98; 8:45 am]

BILLING CODE 4163–19–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. 98P–0062]

Determination That Carbinoxamine Maleate 4–Milligram Immediate-Release Tablets Were Not Withdrawn From Sale for Reasons of Safety or Effectiveness

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) has determined that carbinoxamine maleate (Clistin®) 4-milligram (mg) immediate-release tablets were not withdrawn from sale for reasons of safety or effectiveness. This determination will allow FDA to approve abbreviated new drug applications (ANDA's) for carbinoxamine maleate 4-mg immediate-release tablets.

FOR FURTHER INFORMATION CONTACT: Richard L. Schwartzbard, Center for Drug Evaluation and Research (HFD–7), Food and Drug Administration, 5600 Fishers Lane, Rockville, MD 20855, 301–594–2041.

SUPPLEMENTARY INFORMATION: In 1984, Congress enacted the Drug Price Competition and Patent Term Restoration Act of 1984 (Pub. L. 98–417) (the 1984 amendments), which authorized the approval of duplicate versions of drug products approved under an ANDA procedure. ANDA sponsors must, with certain exceptions, show that the drug for which they are seeking approval contains the same active ingredient in the same strength and dosage form as the ''listed drug,'' which is a version of the drug that was previously approved under a new drug application (NDA). Sponsors of ANDA's do not have to repeat the extensive clinical testing otherwise necessary to gain approval of an NDA. The only clinical data required in an ANDA are data to show that the drug that is the subject of the ANDA is bioequivalent to the listed drug.

The 1984 amendments included what is now section 505(j)(6) of the Federal Food, Drug, and Cosmetic Act (21 U.S.C. 355(j)(6)), which requires FDA to publish a list of all approved drugs. FDA publishes this list as part of the ''Approved Drug Products with Therapeutic Equivalence Evaluations,'' which is generally known as the ''Orange Book.'' Under FDA regulations, drugs are withdrawn from the list if the agency withdraws or suspends approval of the drug's NDA or ANDA for reasons of safety or effectiveness, or if FDA determines that the listed drug was withdrawn from sale for reasons of safety or effectiveness (21 CFR 314.162). Regulations also provide that the agency must make a determination as to whether a listed drug was withdrawn from sale for reasons of safety or effectiveness before an ANDA that refers to that listed drug may be approved (§ 314.161(a)(1) (21 CFR 314.161(a)(1))). FDA may not approve an ANDA that does not refer to a listed drug.

In a citizen petition dated January 22, 1998 (Docket No. 98P–0062/CP1), submitted in accordance with 21 CFR 314.122, Sage Pharmaceuticals requested that the agency determine whether carbinoxamine maleate (Clistin®) 4-mg immediate-release tablets were withdrawn from sale for reasons of safety or effectiveness. Carbinoxamine maleate (Clistin®) 4-mg immediate-release tablets were the subject of approved NDA 8–915.[1] On

[1] NDA 8–915 also covered Clistin® R–A, a controlled-release form of carbinoxamine maleate tablets. In the **Federal Register** of July 29, 1983 (48

January 26, 1993, the R. W. Johnson Pharmaceutical Research Institute notified FDA in writing that carbinoxamine maleate (Clistin®) 4-mg immediate-release tablets were no longer being marketed under NDA 8–915 and requested the withdrawal of that application. FDA complied and announced the withdrawal of approval for NDA 8–915 in the **Federal Register** of March 2, 1994 (59 FR 9989).

FDA has reviewed its records and, under § 314.161, has determined that carbinoxamine maleate 4-mg immediate-release tablets were not withdrawn from sale for reasons of safety or effectiveness. Accordingly, the agency will maintain carbinoxamine maleate 4-mg immediate-release tablets in the ''Discontinued Drug Product List'' section of the Orange Book. The ''Discontinued Drug Product List'' identifies, among other items, drug products that have been discontinued from marketing for reasons other than safety or effectiveness. ANDA's that refer to carbinoxamine maleate 4-mg immediate-release tablets may be approved by the agency.

Dated: May 13, 1998.

William K. Hubbard,

Associate Commissioner for Policy Coordination.

[FR Doc. 98–13468 Filed 5–20–98; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. 98N–0317]

Prompt Review of Supplemental Applications for Approved Devices

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration's (FDA's) Center for Devices and Radiological Health (CDRH) and Center for Biologics Evaluation and Research (CBER), in accordance with the FDA Modernization Act of 1997 (FDAMA), are publishing standards for the prompt review of supplemental applications submitted for devices approved under the Federal Food, Drug, and Cosmetic Act (the act) (21 U.S.C. 301 *et seq.*). Also, in accordance with FDAMA, CDRH and CBER are designating an individual within each center to be responsible for encouraging prompt review of supplements and for working with sponsors to facilitate development and submission of data to support such supplements.

DATES: Written comments by August 19, 1998.

ADDRESSES: Submit written comments concerning this notice to the Dockets Management Branch (HFA–305), Food and Drug Administration, 12420 Parklawn Dr., rm. 1–23, Rockville, MD 20857. Comments should be identified with the docket number found in brackets in the heading of this document.

FOR FURTHER INFORMATION CONTACT:

Robert M. Navazio, Center for Devices and Radiological Health (HFZ–30), Food and Drug Administration, 2098 Gaither Rd., Rockville, MD 20850, 301–594–1282, or

Jerome A. Donlon, Center for Biologics Evaluation and Research (HFM–200), Food and Drug Administration, 1401 Rockville Pike, Rockville, MD 20852–3028, 301–827–3028.

SUPPLEMENTARY INFORMATION:

I. Background

FDAMA was enacted on November 21, 1997, in order to streamline the process of bringing safe and effective drugs, medical devices, and other therapies to the U.S. market. Section 403 of FDAMA addresses FDA's review of supplemental applications (''supplements'') submitted for articles approved under the act or section 351 of the Public Health Service Act.

Section 403(a) of FDAMA requires FDA to publish in the **Federal Register**, not later than 180 days after enactment of FDAMA, standards for the prompt review of supplements. Section 403(b) requires FDA to issue final guidances by that same date to clarify the requirements for, and facilitate the submission of, data to support the approval of supplements. Section 403(b) also requires the guidance to clarify those circumstances in which published matter may be the basis for approval of supplements, to specify data requirements that will avoid duplication of previously submitted data, and to define those supplements that are eligible for priority review. Section 403(c) requires FDA to designate an individual within each center of FDA (except the Center for Food Safety and Applied Nutrition) to be responsible for encouraging prompt review of supplements and working with sponsors to facilitate development and submission of data to support supplements. Section 403(d) requires FDA to implement programs and policies that will foster collaboration between FDA, the National Institutes for Health, and others to identify studies that may support supplements and to encourage sponsors to submit and develop supplements based on such studies.

In this notice, CDRH and CBER are publishing performance standards they have established for the prompt review of premarket approval application (PMA) supplements, in accordance with section 403(a) of FDAMA. Also, the Director, Office of Device Evaluation, CDRH, and the Deputy Director, Medical, CBER are designated as the individuals within each center who will be responsible for encouraging the prompt review of PMA supplements and working with sponsors to facilitate development and submission of data to support supplements, in accordance with section 403(c). Elsewhere in this issue of the **Federal Register**, CDRH is publishing a notice of availability of final guidance to industry to clarify the requirements for, and facilitate the submission of, data to support the approval of supplements, in accordance with section 403(b).

II. FDAMA Section 403(a)

Following approval of a PMA or receipt of an order declaring a product development protocol (PDP) completed, the sponsor of the approved PMA or completed PDP must submit a supplement to the PMA or PDP for review and approval by FDA before making a change affecting the safety and effectiveness of the device, unless the device is of a type for which FDA has advised that an alternate submission is permitted.

FDA measures its performance with respect to review of supplements by tracking and analysis of groups of incoming applications. These groups of submissions are referred to as Receipt Cohorts.

A. PDP Supplements

In accordance with 21 CFR 814.19, a class III device for which a product development protocol has been declared completed by FDA will be considered to have an approved PMA. Accordingly, FDA intends to review PDP supplements in the same timeframe it reviews PMA supplements.

FDA does not have baseline data for PDP supplements because no submissions of such supplements have been received. To the extent applicable, FDA intends to apply to PDP supplements the same performance standards described below for PMA supplements.

FR 34514), FDA withdrew approval of NDA 8–915 as it pertained to Clistine® R–A because no person submitted bioavailability data showing that the product was effective as a controlled-release dosage form.

B. PMA Supplements

In accordance with FDA regulations, PMA supplements ordinarily are required to be reviewed within 180 days (21 CFR 814.39(c)).

The legislative history of section 403 of FDAMA indicates that Congress expected FDA to publish performance standards for those supplements submitted for changes in product use. Therefore, the data that follow do not reflect FDA performance standards for PMA supplements submitted for other changes, e.g., labeling or manufacturing. Historically, FDA has received approximately 300 to 500 PMA supplements per year. Approximately 10 percent of these supplements address changes in the indication for use. Performance for the PMA supplement receipt cohort for changes in indication received during fiscal year (FY) 1996 and FY 97 was just over 70 percent completed within 180 days.

Tracking for PMA supplements will continue to be accomplished using Receipt Cohorts as the basis for program performance. Projected performance for the FY 98 receipt cohort for changes in indication is expected to be 65 percent reviewed within 180 days. This estimate is based on making the best use of available FY 98 resources during a time of increasing workload attributable to implementation of FDAMA. In FY 99, FDA will continue reengineering the device review process with emphasis on these new requirements. If adequate funding is provided, FDA expects that performance will be back to 70 percent in FY 99 and anticipates enhanced performance levels in subsequent years.

III. FDAMA Section 403(c)

FDA has designated the following individuals within CDRH and CBER to work with sponsors to facilitate the development and submission of data to support supplemental applications for approved articles in accordance with section 403(c) of FDAMA:

Director, Office of Device Evaluation, Center for Devices and Radiological Health (HFZ–400), Food and Drug Administration, 9200 Corporate Blvd., Rockville, MD 20850, 301–594–2022, and

Deputy Director, Medical Center for Biologics Evaluation and Research (HFM–1), Food and Drug Administration, 1401 Rockville Pike, Rockville, MD 20852–1448, 301–827–3028.

IV. Comments

Interested persons may, on or before August 19, 1998, submit to the Dockets Management Branch (address above) written comments regarding this notice. Two copies of any comments are to be submitted, except that individuals may submit one copy. Comments are to be identified with the docket number found in brackets in the heading of this document. Received comments may be seen in the office above between 9 a.m. and 4 p.m., Monday through Friday.

Dated: May 18, 1998.

William B. Schultz,

Deputy Commissioner for Policy.

[FR Doc. 98–13721 Filed 5–20–98; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. 98D–0333]

Guidance for Industry, Supplements to Approved Applications for Class III Medical Devices: Use of Published Literature, Use of Previously Submitted Materials, and Priority Review; Availability

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA) is announcing the availability of the guidance entitled, ''Guidance for Industry, Supplements to Approved Applications for Class III Medical Devices: Use of Published Literature, Use of Previously Submitted Materials, and Priority Review.'' The FDA Modernization Act of 1997 (FDAMA) requires the agency to issue final guidance to clarify circumstances in which published matter may be the basis for approval of a supplemental application, specify data requirements that will avoid duplication of previously submitted data by recognizing the availability of data previously submitted in support of an original application and define supplemental applications that are eligible for priority review.

DATES: Written comments concerning this guidance may be submitted at anytime.

ADDRESSES: Submit written requests for single copies on a 3.5'' diskette of the guidance document entitled, ''Guidance for Industry, Supplements to Approved Applications for Class III Medical Devices: Use of Published Literature, Use of Previously Submitted Materials, and Priority Review'' to the Division of Small Manufacturers Assistance (HFZ–220), Center for Devices and Radiological, Food and Drug Administration, 1350 Piccard Dr., Rockville, MD 20850. Send two self-addressed adhesive labels to assist that office in processing your request, or fax your request to 301–443–8818.

Submit written comments on ''Guidance for Industry, Supplements to Approved Applications for Class III Medical Devices: Use of Published Literature, Use of Previously Submitted Materials, and Priority Review'' to the contact persons listed below. See the SUPPLEMENTARY INFORMATION section for information on electronic access to the guidance.

FOR FURTHER INFORMATION CONTACT:

Kathy M. Poneleit, Center for Devices and Radiological Health (HFZ–402), Food and Drug Administration, 9200 Corporate Blvd., Rockville, MD 20850, 301–594–2186; or

Jerome A. Donlon, Center for Biologics Evaluation and Research, 1401 Rockville Pike (HFM–200), Rockville, MD 20852–1448, 301–827–3028.

SUPPLEMENTARY INFORMATION:

I. Background

Section 403(b) of FDAMA (Pub. L.105–115) provides that not later than 180 days after the date of enactment, the Secretary of the Department of Health and Human Services (FDA by delegation) shall issue final guidances to clarify the requirements for, and facilitate the submission of data to support, the approval of supplemental applications for approved articles under the Federal Food, Drug, and Cosmetic Act (the act) (21 U.S.C. 301 et seq.) or section 351 of the Public Health Service Act (42 U.S.C. 262). The guidances shall:

(1) Clarify circumstances in which published matter may be the basis for approval of a supplemental application;

(2) Specify data requirements that will avoid duplication of previously submitted data by recognizing the availability of data previously submitted in support of an original application; and

(3) Define supplemental applications that are eligible for priority review.

Section 403(b) of FDAMA is applicable to multiple centers within FDA. Availability of the draft guidance prepared by the Center for Drug Evaluation and Research (CDER) and the Center for Biologics Evaluation and Research (CBER) (CDER/CBER draft guidance) was announced in the **Federal Register** of March 21, 1997 (62 FR 13650). The CDER/CBER draft guidance describes the use of literature and the types of study design that may support supplemental effectiveness claims for approved drug and biological products. CDRH issued draft guidance

on March 20, 1998, that set forth its perspective on the applicability of the CDER/CBER draft guidance to medical devices.

The agency received two comments on the draft guidance. Both comments encouraged the agency to issue two separate guidance documents, one for devices and one for drugs and biologics, rather than a single guidance document. Also, both comments requested device-specific examples in the guidance document. One comment requested additional guidance on other provisions of FDAMA.

Although CDRH initially had expected the final guidance issued in accordance with 403(b) of the act to be a single agency document that addressed devices, drugs and biologics, both CDRH and CBER have decided, in the interest of clarity and consistent with comments received on the draft guidance, to issue a separate guidance document for medical devices. This final guidance for medical devices builds upon the foundation developed in the CDER/CBER draft guidance regarding the use of published literature, draws upon the existing premarket approval application (PMA) regulation, and refers to earlier guidance documents developed by CDRH that describe efforts to avoid duplication of previously submitted data and that define supplemental applications that are eligible for priority review. In this final guidance, device specific examples have replaced the drug examples presented in the CDER/CBER draft guidance.

This guidance has been revised to account for all class III products approved as PMA's, including humanitarian device exemption (HDE) products and product development protocols (PDP's). A Class III device for which a PDP has been declared completed by FDA is considered to have an approved PMA § 814.19 (21 CFR 814.19). Supplements to PDPs, therefore, will be treated as PMA supplements for purposes of this guidance. This guidance also provides examples of how the use of published literature may be used in support of a PMA, PDP, or HDE supplement.

Published literature would most frequently be used to support supplements for new indications for use of an approved device. In accordance with § 814.110, an applicant seeking approval for a new indication for use for an approved humanitarian use device must submit an original HDE. Therefore, this guidance would apply to HDE supplements only in unusual circumstances. The agency intends to issue additional guidance documents on other provisions of FDAMA and will solicit public comment on those guidances in accordance with FDA's Good Guidance Practices.

II. Significance of Guidance

This guidance document represents the agency's current thinking on ''Guidance for Industry, Supplements to Approved Applications for Class III Medical Devices: Use of Published Literature, Use of Previously Submitted Materials, and Priority Review.'' Both the Center for Devices and Radiological Health (CDRH) and the Center for Biologics Evaluation and Research (CBER) have responsibilities for the regulation of medical devices. This document applies to medical devices regulated by either CDRH or CBER and reflects the current thinking of both centers on the subject of this guidance. This document does not apply to medical devices licensed by CBER. This document is being issued as final guidance. 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 applicable statute, regulations, or both.

The agency has adopted good guidance practices (GGP's), which set forth the agency's policies and procedures for the development, issuance, and use of guidance documents (62 FR 8961, February 27, 1997). This guidance document is issued as a Level 1 guidance consistent with GGPs. Written comments may be submitted at any time.

III. Electronic Access

In order to receive ''Guidance for Industry, Supplements to Approved Applications for Class III Medical Devices: Use of Published Literature, Use of Previously Submitted Materials, and Priority Review'' via your fax machine, call the CDRH Facts-On-Demand (FOD) system at 800–899–0381 or 301–827–0111 from a touch-tone telephone. At the first voice prompt press 1 to access DSMA Facts, at second voice prompt press 2, and then enter the document number (380) followed by the pound sign (#). Then follow the remaining voice prompts to complete your request.

Persons interested in obtaining a copy of the guidance may also do so using the World Wide Web (WWW). CDRH maintains an entry on the World Wide Web for easy access to information including text, graphics, and files that may be downloaded to a personal computer with access to the Web. Updated on a regular basis, the CDRH home page includes ''Guidance for Industry, Supplements to Approved Applications for Class III Medical Devices: Use of Published Literature, Use of Previously Submitted Materials, and Priority Review,'' device safety alerts, **Federal Register** reprints, information on premarket submissions (including lists of approved applications and manufacturers' addresses), small manufacturers' assistance, information on video conferencing and electronic submissions, mammography matters, and other device-oriented information. The CDRH home page may be accessed at http://www.fda.gov/cdrh. This guidance is also available from CBER on the World Wide Web at http://www.fda.gov/cber/guidelines.htm.

A text-only version of the CDRH Web site is also available from a computer or VT–100 compatible terminal by dialing 800–222–0185 (terminal settings are 8/1/N). Once the modem answers, press Enter several times and then select menu choice 1: FDA BULLETIN BOARD SERVICE. From there follow instructions for logging in, and at the BBS TOPICS PAGE, arrow down to the FDA home page (do not select the first CDRH entry). Then select Medical Devices and Radiological Health. From there select CENTER FOR DEVICES AND RADIOLOGICAL HEALTH for general information, or arrow down for specific topics.

IV. Comments

Interested persons may, at any time, submit to the contact person (address above) written comments regarding this final guidance. Such comments will be considered when determining whether to amend the current guidance. Two copies of any comments are to be submitted, except that individuals may submit one copy. Comments are to be identified with the docket number found in brackets in the heading of this document. The guidance document may be seen in the Dockets Management Branch between 9 a.m. and 4 p.m., Monday through Friday.

Dated: May 18, 1998.

William B. Schultz,

Deputy Commissioner for Policy.

[FR Doc. 98–13720 Filed 5–20–98; 8:45 am]

BILLING CODE 4160–01–F

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Health Care Financing Administration

[Document Identifier: HCFA–R–237]

Agency Information Collection Activities: Proposed Collection; Comment Request

In compliance with the requirement of section 3506(c)(2)(A) of the Paperwork Reduction Act of 1995, the Health Care Financing Administration (HCFA), Department of Health and Human Services, is publishing the following summary of proposed collections for public comment. Interested persons are invited to send comments regarding the burden estimate or any other aspect of this collection of information, including any of the following subjects: (1) The necessity and utility of the proposed information collection for the proper performance of the agency's functions; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

Type of Information Collection Request: New Collection; *Title of Information Collection:* Multi-State Evaluation of Dual Eligibles Demonstration; *Form No.:* HCFA–R–237 OMB #0938–NEW; *Use:* This survey provides information needed to evaluate dual eligible demonstrations on issues of satisfaction and gather health and functional status to be used in other analyses. Dual eligible demonstrations provide HCFA the opportunity to determine whether changes in payment and reimbursement and alternative ways to provide health services results in better coordination, increased satisfaction, and improved outcomes of those eligible for both Medicare and Medicaid. Respondents to the survey include demonstration enrollees both living in the community and in institutions, their families, disenrollees and corresponding comparison groups.

Frequency: One time submission; *Affected Public:* Individuals or Households; *Number of Respondents:* 2,900; *Total Annual Responses:* 2,900; *Total Annual Hours:* 2,106.

To obtain copies of the supporting statement for the proposed paperwork collections referenced above, E-mail your request, including your address and phone number, to Paperwork@hcfa.gov, or call the Reports Clearance Office on (410) 786–1326. Written comments and recommendations for the proposed information collections must be mailed within 60 days of this notice directly to the HCFA Paperwork Clearance Officer designated at the following address: HCFA, Office of Information Services, Information Technology Investment Management Group, Division of HCFA Enterprise Standards, Attention: John Rudolph, Room C2–26–17, 7500 Security Boulevard, Baltimore, Maryland 21244–1850.

Dated: May 11, 1998.

John P. Burke III,

HCFA Reports Clearance Officer, Division of HCFA Enterprise Standards, Health Care Financing Administration.

[FR Doc. 98–13575 Filed 5–20–98; 8:45 am]

BILLING CODE 4120–03–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Caner Institute; Meeting

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following meeting of the National Cancer Institute Frederick Cancer Research and Development Center Advisory Committee.

The open portion of the meeting will be limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the contact person in advance of the meeting.

Committee Name: Frederick Cancer Research and Development Center Advisory Committee.

Date: June 11–12, 1998.

Place: Frederick Cancer Research and Development Center, Building 549, Executive Board Room, Frederick, Maryland 21702–1201.

Open: 8:30 a.m.—10:00 a.m.

Agenda: Discussion of administrative matters such as future meetings, budget and information items related to the operation of the NCI Frederick Cancer Research and Development Center.

Closed: June 11–10:00 a.m. to Recess, June 12–10:00 a.m. to Adjournment.

Agenda/Purpose: Presentations and discussions of previous site visit report and response for the Molecular Basis of Carcinogenesis Laboratory held December 11–12, 1997. There will be a site review of the Chemistry of Carcinogenesis Laboratory and a review of two Principal Investigators in the Molecular Virology and Carcinogenesis Laboratory both with ABL–Basic Research Program contract.

Contact Person: David J. Goldstein, Ph.D., Executive Secretary, Frederick Cancer Research and Development Center, P.O. Box B, Frederick, MD 21702–1201, Telephone: 301–846–1108.

The meeting will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552(C)(6), Title 5, U.S.C. The report and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the programs, disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Program Numbers: 93.393, Cancer Cause and Prevention Research; 93.394, Cancer Detection and Diagnosis Research; 93.395, Cancer Treatment Research; 93.396, Cancer Biology Research; 93.397, Cancer Centers Support; 93.398, Cancer Research Manpower; 93.399, Cancer Control)

Dated: May 13, 1998.

Anna Snouffer,

Acting NIH Committee Management Officer.

[FR Doc. 98–13535 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Cancer Institute; Notice of Meeting

Pursuant to Section 10(a) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of a meeting of the President's Cancer Panel.

This meeting will be open to the public as indicated below, with attendance by the public limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify Linda Quick-Cameron, Committee Management Officer, National Cancer Institute, Executive Plaza North, Room 609, 6130 Executive Blvd., MSC 7410, Bethesda, MD 20892–7410 (301/496–5708). A summary of the meeting and the roster of committee members will be provided upon request. Other information pertaining to the meeting may be obtained from the contract person indicated below.

Committee Name: President's Cancer Panel.

Date: June 2, 1998.

Place: Yale University, Hope 110 Lecture Hall, 315 Cesar Street, New Haven, CT.

Open: 9:30 a.m. to Adjournment.

Agenda: Quality of Cancer Care/Quality of Life, Defining Quality of Life and Survivorship.

Contract Person: Maureen O. Wilson, Ph. D., Executive Secretary, National Cancer

Institute, Building 31, Room 4A48, Bethesda, MD 20892, Telephone: (301) 496–1148.

This notice is published less than 15 days prior to the meeting due to the urgent need to meet timing limitations imposed by the review and funding cycle.

Dated: May 13, 1998.

Anna Snouffer,

Acting NIH Committee Management Officer.

[FR Doc. 98–13536 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Eye Institute; Meeting of Board of Scientific Counselors

Pursuant to Pub. L. 92–463, notice is hereby given of the meeting of the Board of Scientific Counselors, National Eye Institute, June 8 and 9, 1998 in Building 10, Room 10B16, National Institutes of Health, Bethesda, Maryland.

This meeting will be open to the public on June 8 from 9 a.m. until approximately 10 a.m. for general remarks by the Director, Intramural Research Program, National Eye Institute (NEI), on matters concerning the intramural program of the NEI. Attendance by the public will be limited to space available.

In accordance with provisions set forth in sec. 552b(c)(6), Title 5, U.S.C. and sec. 10(d) of Pub. L. 92–463, the meeting will be closed to the public on June 8 from approximately 10 a.m. until recess and on June 9 from 8:30 a.m. until adjournment for the review, discussion, and evaluation of individual projects conducted by the Division of Biometry and Epidemiology. These evaluations and discussions could reveal personal information concerning individuals associated with the projects, including consideration of personnel qualifications and performance, and the competence of individual investigators, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Ms. Colleen Genovese, Counselor Assistant, NEI, Building 10, Room 10N202 Bethesda, Maryland 20892, (301) 496–3123, will provide a summary of the meeting, roster of committee members, and substantive program information upon request. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should contact Ms. Genovese in advance of the meeting.

(Catalog of Federal Domestic Assistance Program No. 93.867, Vision Research; National Institutes of Health)

Dated: May 14, 1998.

Anna Snouffer,

Acting NIH Committee Management Officer.

[FR Doc. 98–13529 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Heart, Lung, and Blood Institute; Notice of Closed Meetings

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following National Heart, Lund, and Blood Institute meetings:

Name of Committee: Heart, Lung, and Blood Program Project Review Committee.

Date: June 25, 1998.

Time: 8:00 a.m.

Place: Holiday Inn Silver Spring, 8777 Georgia Avenue, Silver Spring, Maryland 20910.

Contact Person: Jeffrey H. Hurst, Ph.D., Scientific Review Administrator, NHLBI/Review Branch, Two Rockledge Center, Room 7208, 6701 Rockledge Drive, Bethesda, MD 20892–7924, (301) 435–0303.

Purpose/Agenda: To review and evaluate program project grant applications.

Name of Committee: National Heart, Lung, and Blood Special Emphasis Panel (Thrombocytopenia: Pathogenesis and Treatment).

Date: June 10, 1998.

Time: 8:00 a.m.

Place: Gaithersburg Marriott Washingtonian Center, 9751 Washingtonian Boulevard, Gaithersburg, Maryland 20878.

Contact Person: Eric H. Brown, Ph.D., Two Rockledge Center, Room 7204, 6701 Rockledge Drive, Bethesda, Maryland 20892–7924, (301) 435–0299.

Purpose/Agenda: To review and evaluate grant applications.

These meetings will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552b(c)(6), Title 5, U.S.C. Applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Programs Nos. 93.837, Heart and Vascular Diseases Research; 93.838, Lung Diseases Research; and 93.839, Blood Diseases and Resources Research, National Institutes of Health)

Dated: May 14, 1998.

Anna Snouffer,

Acting Committee Management Officer, NIH.

[FR Doc. 98–13541 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Neurological Disorders and Stroke Division of Extramural Activities; Notice of Closed Meeting

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following meeting.

Name of Committee: National Institute of Neurological Disorders and Stroke Special Emphasis Panel (Telephone Conference Call).

Date: June 10, 1998.

Time: 1:00 p.m.

Place: National Institutes of Health, 7550 Wisconsin Avenue, Room 9C10, Bethesda, MD 20892.

Contact Person: Dr. Katherine Woodbury-Harris, Mr. Phillip Wiethorn, Scientific Review Administrators, Scientific Review Branch, NINDS, National Institutes of Health, 7550 Wisconsin Avenue, Room 9C10, Bethesda, MD 20892, (301) 496–9223.

Purpose/Agenda: To review and evaluate RFP Contract Proposal(s).

The meeting will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552b(c)(6), Title 5, U.S.C. Applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Program No. 93.853, Clinical Research Related to Neurological Disorders; No. 93.854, Biological Basis Research in the Neurosciences)

Dated: May 14. 1998.

Anna Snouffer,

Acting NIH Committee Management Officer.

[FR Doc. 98–13528 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Neurological Disorders and Stroke Division of Extramural Activities; Closed Meeting

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following meeting:

Name of Committee: National Institute of Neurological Disorders and Stroke Special Emphasis Panel.

Dates: July 27, 28, 29, 1998.

Time: 8:30 a.m.

Place: ANA Hotel, 2401 M Street N.W., Washington, DC 20037, (202) 429–2400.

Phone: (202) 429–2400.

Contact Person: Dr. Lillian Pubols, Chief, Scientific Review Branch, NINDS, National Institutes of Health, 7550 Wisconsin Avenue, Room 9C10, Bethesda, Maryland 20892, (301) 496–9223.

Purpose/Agenda: To review and evaluate grant applications.

The meeting will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552b(c)(6), Title 5, U.S.C. Applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Program No. 93.853, Clinical Research Related to Neurological Disorders; No. 93.854, Biological Basis Research in the Neurosciences)

Dated: May 14, 1998.

Anna Snouffer,

Acting NIH Committee Management Officer.

[FR Doc. 98–13530 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institute of Health

National Institute of Environmental Health Sciences; Closed Meeting

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following National Institute of Environmental Health Sciences Special Emphasis Panel (SEP) meeting:

Name of SEP: Treatment for Lead-Exposed Children Follow-up.

Date: June 12, 1998.

Time: 9:00 a.m.

Place: National Institute of Environmental Health Sciences, East Campus, Building 4401, Room 3446, Research Triangle Park, North Carolina 27709.

Contact Person: Dr. Ethel Jackson, Scientific Review Administrator, National Institute of Environmental Health Sciences, P.O. Box 12233 MD EC–24, Research Triangle Park, NC 37709, (919) 541–7826.

Purpose/Agenda: To review and evaluate grant applications.

This meeting will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552b(c)(6), Title 5, U.S.C. Grant applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Programs Nos. 93.113, Biological Response to Environmental Agents; 93.114, Applied Toxicological Research and Testing; 93.115, Biometry and Risk Estimation; 93.894, Resource and Manpower Development, National Institutes of Health).

Dated: May 14, 1998.

Anna Snouffer,

Acting Committee Management Officer, NIH

[FR Doc. 98–13531 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Environmental Health Sciences; Closed Meeting

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following National Institute of Environmental Health Sciences Special Emphasis Panel (SEP) meeting:

Name of SEP: Review of Conference Grants—R13s (Telephone Conference Call).

Date: June 3, 1998.

Time: 1:00 p.m.

Place: National Institute of Environmental Health Sciences, East Campus, Building 4401, Room 3446, Research Triangle Park, NC 27709.

Contact Person: Dr. Carol Shreffler, National Institute of Environmental Health Sciences, P.O. Box 12233, MD EC–24, Research Triangle Park, NC 27709, (919) 541–1445.

Purpose/Agenda: To review and evaluate grant applications.

This meeting will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552b(c)(6), Title 5, U.S.C. Grant applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

This notice is being published less than fifteen days prior to this meeting due to the urgent need to meet timing limitations imposed by the grant/contract review and funding cycle.

(Catalog of Federal Domestic Assistance Programs Nos. 93.113, Biological Response to Environmental Agents; 93.114, Applied Toxicological Research and Testing; 93.115, Biometry and Risk Estimation; 93.894, Resource and Manpower Development, National Institutes of Health)

Dated: May 14, 1998.

Anna Snouffer,

Acting Committee Management Officer, NIH.

[FR Doc. 98–13532 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and infectious Diseases; Closed Meeting

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following National Institute of Allergy and Infectious Diseases Special Emphasis Panel (SEP) meeting:

Name of SEP: Inmate Immunity in Vertebrates and Insects and Inmate Immune Response to Microbial Infection.

Date: June 26, 1998.

Time: 8:30 a.m. to Adjournment.

Place: Bethesda Ramada Hotel and Conference Center, Parlor Room, 8400 Wisconsin Avenue, Bethesda, MD 20814, (301) 496–2550.

Contact Person: Dr. Vassil Georgiev, Scientific Review Adm., 6003 Executive Boulevard, Solar Bldg., Room 4C04, Bethesda, MD 20892, (301) 496–8206.

Purpose/Agenda: To evaluate grant applications.

The meeting will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552b(c)(6), Title 5, U.S.C. Applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Programs Nos. 93.855, Immunology, Allergic and Immunologic Diseases Research; 93.856, Microbiology and Infectious Diseases Research, National Institutes of Health)

Dated: May 14, 1998.

Anna Snouffer,

Acting Committee Management Officer, NIH.

[FR Doc. 98–13533 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Dental Research; Meeting of Board of Scientific Counselors

Pursuant to Pub. L. 92–463, notice is hereby given of a meeting of the Board of Scientific Counselors, National

Institute of Dental Research, on June 4–5, 1998, in Building 30, Trendley Dean Conference Room, National Institutes of Health, Bethesda, Maryland. The meeting will be open to the public from 9:00 a.m. to 5:00 p.m. on June 4 for the Pain and Neurosensroy Mechanisms Branch presentations and from 8:30 a.m. to 10:30 a.m. on June 5 for a tour of the facilities and poster presentations, Building 49. Attendance by the public will be limited to space available.

In accordance with the provisions set forth in sec. 552b(c)(6), Title 5, U.S.C. and sec. 10(d) of Pub. L. 92–463, the meeting will be closed to the public from 9:30 a.m. until 9:00 a.m. on June 4 an from 10:30 a.m. until adjournment on June 5 for the review, discussion, and evaluation of individual programs and projects conducted by the National Institute of Dental Research (NIDR), including consideration of personnel qualifications and performance, the competence of individual investigators, and similar items, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Mr. Brent Jaquet, Director, Office of Communications and Health Education, NIDR, NIH, Building 31, Room 5B55, Bethesda, Maryland 20892 (telephone: 301–496–6705; e-mail: JaquetB@OD31.nidr.nih.gov) will provide a summary of the meeting, roster of committee members and substantive program information.

Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should contact the Executive Secretary listed above in advance of the meeting.

(Catalog of Federal Domestic Assistance Program No. 93.121, Oral Diseases and Disorders Research)

Dated: May 14, 1998.

Anna Snouffer,

Acting Committee Management Officer, NIH.

[FR Doc. 98–13534 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Alcohol Abuse and Alcoholism; Notice of Closed Meetings

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following meetings:

Purpose/Agenda: To review and evaluate a grant application.

Name of Committee: National Institute on Alcohol Abuse and Alcoholism Special Emphasis Panel.

Date of Meeting: June 18, 1998.

Time: 3:30 p.m. to adjournment.

Place of Meeting: Radisson Suite Resort, Hilton Head Island, 12 Park Lane, Hilton Head, South Carolina 29928.

Contact Person: Ron Suddendorf, Ph.D., 6000 Executive Blvd., Suite 409, Bethesda, MD 20892–7003, 301–443–2926.

Name of Committee: National Institute on Alcohol Abuse and Alcoholism Special Emphasis Panel.

Date of Meeting: June 19, 1998.

Time: 4:00 p.m. to adjournment.

Place of Meeting: Holiday Inn Oceanfront, Palm Meeting Room, Hilton Head Island, South Carolina 29938.

Contact Person: Elsie D. Taylor, 6000 Executive Blvd., Suite 409, Bethesda, MD 20892–7003, 301–443–9787.

The meetings will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552b(c)(6), Title 5 U.S.C. The proposal and discussions could reveal confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the proposal, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance, Program Nos. 93.271, Alcohol Research Career Development Awards for Scientists and Clinicians; 93.272, Alcohol National Research Service Awards for Research Training; 93.273, Alcohol Research Programs; and 93.891, Alcohol Research Center Grants; National Institutes of Health)

Dated: May 13, 1998.

Anna Snouffer,

Acting Committee Management Officer, NIH.

[FR Doc. 98–13537 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Allergy and Infectious Diseases; Notice of Closed Meeting

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following National Institute of Allergy and Infectious Diseases Special Emphasis Panel (SEP) meeting:

Name of SEP: AIDS International Training and Research Program.

Date: June 8–10, 1998.

Time: 9:00 a.m. to Adjournment.

Place: Holiday Inn, Bethesda, Versailles Room, 8120 Wisconsin Avenue, Bethesda, MD 20814, (301) 652–2000.

Contact Person: Dr. Stanley Oaks, Scientific Review Adm., 6003 Executive Boulevard, Solar Bldg., Room 4C06, Bethesda, MD 20892, (301) 496–7042.

Purpose/Agenda: To evaluate grant applications.

The meeting will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552b(c)(6), Title 5, U.S.C. Applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Programs Nos. 93.855, Immunology, Allergic and Immunologic Diseases Research; 93.856 Microbiology and Infectious Diseases Research, National Institutes of Health)

Dated: May 13, 1998.

Anna Snouffer,

Acting Committee Management Officer, NIH.

[FR Doc. 98–13538 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Drug Abuse; Notice of Closed Meetings

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following National Institute on Drug Abuse (NIDA) Initial Review Group and Special Emphasis Panel meetings.

Purpose/Agenda: To review and evaluate grant application and contract proposals.

Name of Committee: NIDA Special Emphasis Panel (Medication Development).

Date: June 2, 1998.

Time: 8:30 a.m.

Place: Double Tree Hotel, 1750 Rockville Pike, Rockville, MD 20854.

Contact Person: Khursheed Asghar, Ph.D., Scientific Review Administrator, Office of Extramural Program Review, National Institute on Drug Abuse, 5600 Fishers Lane, Room 10–42, Telephone (301) 443–2620.

Name of Committee: Basic Behavioral Science Research Subcommittee.

Date: June 2–3, 1998.

Time: 8:30 a.m.

Place: Key Bridge Marriott Hotel, 1401 Lee Highway, Arlington, VA 22209.

Contact Person: Mark Swieter, Ph.D., Scientific Review Administrator, Office of Extramural Program Review, National Institute on Drug Abuse, 5600 Fishers Lane, Room 10–42, Telephone (301) 443–2620.

Name of Committee: NIDA Special Emphasis Panel (Contract Review—''Evaluation of the National Youth Anti-Drug Media Campaign'').

Date: June 9, 1998.

Time: 9:00 a.m.

Place: Holiday Inn Chevy Chase, 5520 Wisconsin Avenue, Chevy Chase MD 20818.

Contact Person: Mr. Eric Zatman, Review Administrator, Office of Extramural Program Review, National Institute on Drug Abuse, 5600 Fishers Lane, Room 10–42, Telephone (301) 443–1644.

Name of Committee: Epidemiology and Prevention Research Subcommittee.

Date: June 9–11, 1998.

Time: 8:30 a.m.

Place: Crystal City Courtyard Marriott, 2899 Jefferson Davis Highway, Arlington, VA 22202.

Contact Person: Susan L. Coyle, Ph. D., Scientific Review Administrator, Office of Extramural Program Review, National Institute on Drug Abuse, 5600 Fishers Lane, Room 10–22, Telephone (301) 443–2620.

Name of Committee: NIDA Special Emphasis Panel (Contract Review—''GMP Synthesis of Bulk Drug Substances'').

Date: June 15, 1998.

Time 9:00 a.m.

Place: Double Tree Hotel, 1750 Rockville Pike, Rockville, MD 20854.

Contact Person: Mr. Lyle Furr, Review Administrator, Office of Extramural Program Review, National Institute on Drug Abuse, 5600 Fishers Lane, Room 10–42, Telephone (301) 443–1644.

The meeting will be closed in accordance with provisions set forth in secs. 552b(c)(4) and 552(c)(6), Title 5, U.S.C. The applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Program Numbers: 93.277, Drug Abuse Research Scientist Development and Research Scientist Awards; 93.278, Drug Abuse National Research Service Awards for Research Training; 93.279, Drug Abuse Research Programs)

Dated May 13, 1998.

Anna Snouffer,

Acting NIH Committee Management Officer.

[FR Doc. 98–13539 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Deafness and Other Communications Disorders; Notice of Closed Meeting

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 United States Code Appendix 2), notice is hereby given of the following meeting:

Name of Committee: National Institute on Deafness and Other Communications Disorders Special Emphasis Panel.

Date: June 9, 1998.

Time: 3 pm to adjournment.

Place: 6120 Executive Blvd, Rockville MD 20852, (telephone conference call).

Contact Person: Richard S. Fisher, Ph.D., Scientific Review Administrator, NIDCD/DEA/SRB, EPS Room 400C, 6120 Executive Boulevard, Bethesda MD 20892–7180, 301–496–8693.

Purpose/Agenda: To review and evaluate grant applications. The meeting will be closed in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5, United States Code. The applications and/or proposals and the discussion could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Program No. 93.173 Biological Research Related to Deafness and Communication Disorders)

Dated: May 14, 1998.

Anna Snouffer,

Acting Committee Management Officer, NIH.

[FR Doc. 98–13540 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Dental Research; Notice of Closed Meetings

Pursuant to Section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. Appendix 2), notice is hereby given of the following National Institute of Dental Research Special Emphasis Panel (SEP) meetings:

Name of SEP: National Institute of Dental Research Special Emphasis Panel-Review of K08 (98–33).

Dates: May 15, 1998.

Time: 8:00 a.m.

Place: Natcher Building, Rm. 4AN–44F, National Institutes of Health, Bethesda, MD 20892 (teleconference).

Contact Person: Dr. William Gartland, Scientist Review Administrator, 4500 Center Drive, Natcher Building, Room 4AN–44F, Bethesda, MD 20892, (301) 594–2372.

Purpose/Agenda: To evaluate and review grant applications and/or contract proposals.

Name of SEP: National Institute of Dental Research Special Emphasis Panel-Review of R03s (98–32).

Dates: May 28, 1998.

Time: Noon.

Place: Natcher Building, Rm. 4AN–445, National Institutes of Health, Bethesda, MD 20892 (teleconference).

Contact Person: Dr. William Gartland, Scientist Review Administrator, 4500 Center Drive, Natcher Building, Room 4AN–44F, Bethesda, MD 20892, (301) 594–2372.

Purpose/Agenda: To evaluate and review grant applications and/or contract proposals.

This notice is being published less than fifteen days prior to the meeting due to the urgent need to meet timing limitations imposed by the review and funding cycle.

These meetings will be closed in accordance with the provisions set forth in secs. 552b(c)(4) and 552b(c)(6), Title 5, U.S.C. Applications and/or proposals and the discussions could reveal confidential trade secrets or commercial property such as patentable material and personal information concerning individuals associated with the applications and/or proposals, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

(Catalog of Federal Domestic Assistance Program No. 93.121, Oral Diseases and Disorders Research)

Dated: May 14, 1998.

Anna Snouffer,

Acting Committee Management Officer, NIH.

[FR Doc. 98–13542 Filed 5–20–98; 8:45 am]

BILLING CODE 4140–01–M

DEPARTMENT OF THE INTERIOR

Geological Survey

Technology Transfer Act of 1986

AGENCY: U.S. Geological Survey, Interior.

ACTION: Notice of proposed Cooperative Research and Development Agreement (CRADA) negotiations.

SUMMARY: The United States Geological Survey (USGS) is planning to enter into a Cooperative Research and Development Agreement (CRADA) with the Environmental Systems Research Institute (ESRI), Redlands, CA. The purpose of the CRADA is to conduct research and development in the management, access, distribution, and application of geospatial data related to elevation, hydrologic, watershed, national atlas, raster, and image data programs. Any other organization interested in pursuing the possibility of a CRADA for similar kinds of activities should contact the USGS.

ADDRESSES: Inquiries may be addressed to the Acting Chief of Research, U.S. Geological Survey, National Mapping Division, 500 National Center, 12201 Sunrise Valley Drive, Reston, Virginia 20192; Telephone (703) 648–4643, facsimile (703) 648–4706; Internet ''ebrunson@usgs.gov.''

FOR FURTHER INFORMATION CONTACT: Ernest B. Brunson, address above.

SUPPLEMENTARY INFORMATION: This notice is to meet the USGS requirement stipulated in the Survey Manual.

Dated: May 7, 1998.

Richard E. Witmer,

Chief, National Mapping Division.

[FR Doc. 98–13583 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–Y7–M

DEPARTMENT OF THE INTERIOR

Bureau of Indian Affairs

Proclaiming Certain Lands as Reservation for the Cow Creek Band of Umpqua Tribe of Indians in Oregon

AGENCY: Bureau of Indian Affairs, Interior.

ACTION: Notice of reservation proclamation.

SUMMARY: The Assistant Secretary—Indian Affairs proclaimed approximately 19.99 acres as an addition to the reservation of the Cow Creek Band of Umpqua Tribe of Indians on April 30, 1998. This notice is published in the exercise of authority delegated by the Secretary of the Interior to the Assistant Secretary—Indian Affairs by 209 DM 8.1.

FOR FURTHER INFORMATION CONTACT: Larry E. Scrivner, Bureau of Indian Affairs, Division of Real Estate Services, MS–4510/MIB/Code 220, 1849 C Street, N.W., Washington, D.C. 20240, telephone (202) 208–7737.

SUPPLEMENTARY INFORMATION: A proclamation was issued according to the Act of June 18, 1934 (48 Stat. 986; 25 U.S.C. 467), for the tract of land described below. The land was proclaimed to be an addition to and part of the reservation of the Cow Creek Band of Umpqua Tribe of Indians for the exclusive use of Indians on that reservation who are entitled to reside at the reservation by enrollment or tribal membership.

Reservation of the Cow Creek Band Of Umpqua Tribe of Indians

Douglas County, Oregon

The following described real property is located in the Southeast quarter of Section 32, Township 29 South, Range 5 West, Willamette Meridian, Douglas County, Oregon: Beginning at a 5/8 inch iron rod located on the easterly right-of-way boundary of U.S. Interstate Highway No. 5, said 5/8 inch iron rod bears North 89°36′02″ East 4,377.78 feet from the west-northwest corner of the Thomas Whitted Donation Land Claim No. 44; thence along said easterly right-of-way boundary of said U.S. Interstate Highway No. 5, North 50°59′35″ East 207.83 feet to a 5/8 inch iron rod; thence leaving said easterly right-of-way boundary of said U.S. Interstate Highway No. 5 and running South 43°50′08″ East along the northeasterly line of that property described in Recorder's No. 95–12052, Records of Douglas County, Oregon, 778.78 feet to a 5/8 inch iron rod located on the westerly boundary of the Tri-City State Airport; thence along said westerly boundary of said Tri-City State Airport, South 49°45′00″ West 1,162.50 feet to a railroad iron fence corner; thence leaving said westerly boundary of said Tri-City State Airport, and running North 43°49′11″ West along the southwesterly line of that property described in Recorder's No. 95–12052, Records of Douglas County, Oregon, 722.64 feet to a 5/8 inch iron rod located on the said easterly right-of-way boundary of said U.S. Interstate Highway No. 5; thence along said easterly right-of-way boundary of said U.S. Interstate Highway No. 5, North 46°06′30″ East 952.93 feet to the point of beginning.

Together with a perpetual easement for access to a well, granted by George D. Weaver to Donald L. Mauck and Hulda M. Mauck, by instrument dated January 29, 1971, and recorded December 10, 1973, in Book 535, Page 200, Recorder's No. 73–17681, Records of Douglas County, Oregon.

Also together with a perpetual easement for installation and maintenance of a water pump and irrigation pipeline granted by the Oregon State Board of Aeronautics, to Donald L. Mauck and Hulda M. Mauck, husband and wife, George D. Weaver, and to the Weaver Water Improvement District, by easement dated October 17, 1966, and recorded December 7, 1966, in Book 382, Recorder's No. 66–13325, Records of Douglas County, Oregon. Containing 19.99 acres, more or less.

Title to the land described above is conveyed subject to any valid existing easements for public roads and highways, for public utilities and for railroads and pipelines and any other rights-of-way or reservations of record.

Dated: April 30, 1998.

Kevin Gover,

Assistant Secretary—Indian Affairs.

[FR Doc. 98–13470 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–02–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[AZ–070–07–1230–00; 8371]

Arizona: Lake Havasu Shoreline Project for 1998–1999 and Subsequent Use Seasons; Establishment of Fee Campsites and Supplementary Rules, Lake Havasu Field Office, Arizona

AGENCY: Bureau of Land Management, Interior.

ACTION: Establishment of fees and supplementary rules for the use of boat-access shoreline campsites along Lake Havasu, a manmade lake on the Arizona/California state line.

SUMMARY: The Bureau of Land Management (BLM) Lake Havasu Field Office announces establishment of the Lake Havasu Shoreline Project. The program, initiated in 1997, manages the shoreline riparian area. It includes the preexisting shoreline camp sites as federal fee camp sites under the authorities described in 36 CFR part 71. The camp sites had been developed as designated fee sites by the Arizona State Parks Department while these lands were under a lease from the Bureau of Land Management. The lease was voluntarily terminated, leaving the developed sites to return to the jurisdiction of the BLM.

EFFECTIVE DATE: May 15, 1998.

FOR FURTHER INFORMATION CONTACT: Don Applegate, Project Manager, Lake Havasu Field Office, 2610 Sweetwater Avenue, Lake Havasu City, Arizona, 86406, telephone (520) 505–1244; E–mail dappleg@az.blm.gov.

SUPPLEMENTARY INFORMATION: The primary purpose of the Shoreline Project is to provide long-term areas for boating and camping use. The sites designated as campsites are, in most cases, the traditional use areas of boat camping visitors. Designated sites were selected by Arizona State Parks using criteria based on visitor use patterns, availability of shoreline access, and a need to establish sanitation facilities in heavily-used riparian areas.

This program is being established to safely and properly accommodate the increasing demand for boat camping visits and to provide natural resource protection through improved management of the camping use and the riparian area. The designation of fee campsites assures that specific locations are available for such use year after year.

Authority for the designation of fee campsites is contained in Title 43, Code of Federal Regulations, Part 8360, Subpart 8365, Sections 2 and 2–3.

Authority for the payment of fees is in Title 36, Code of Federal Regulations, Subpart 71. Authority for including this project in the Fee Demonstration Pilot program is contained in the Omnibus Budget Reconciliation Act of 1993 (Public Law 103–66) and the FY 1996 Appropriations Act (Public Law 104–134).

The authority for establishing supplementary rules is contained in Title 43, Subpart 8365, Section 1–6. The shoreline campsite supplementary rules have been developed to manage continued use of the sites until a management plan can be completed. These rules will be available in the local office having jurisdiction over the sites affected, and will be posted at the sites. Violations of supplementary rules are punishable as class A misdemeanors.

The following are the legal descriptions for each of the shoreline campsites:

Legal Locations of Lake Havasu Shoreline Campsites

The following is a list of the 125 shoreline campsites with a legal location to the nearest quarter-quarter-quarter section. The list is organized to reflect that many of the camps are located in small clusters under a single common name. In general, it starts with the northermost sites and ends with the southernmost.

Northern Sites

Gila and Salt River Meridian

Bluebird 1, 2, & 3
T. 13 N., R. 20 W., Sec. 25, NW¼SW¼NW¼
Wren Cove 1, 2, & 3
T. 13 N., R. 20 W., Sec. 25, SE¼SW¼NW¼
Mallard Cove 1
T. 13 N., R. 20 W., Sec. 25, NE¼NE¼SW¼
Mallard Cove 2, 3, 4, 5, & 6
T. 13 N., R. 20 W., Sec. 25, NW¼NE¼SW¼
Teal Point 1, 2, & 3
T. 13 N., R. 20 W., Sec. 25, SW¼NE¼SW¼
Widgeon Key
T. 13 N., R. 20 W., Sec. 25, NW¼SW¼SW¼
Widgeon Key 1, 2, & 4 (There is no #3)
T. 13 N., R. 20 W., Sec. 25, NW¼SW¼SE¼
Road Runner 1, 2, 3, & 4
T. 13 N., R. 20 W., Sec. 25, SE¼SW¼SE¼
Heron Cove & Heron Cove 2
T. 13 N., R. 20 W., Sec. 36, NW¼NE¼NE¼
Cholla
T. 13 N., R. 20 W., Sec. 36, NE¼NE¼NE¼
Solitude Cove
T. 13 N., R. 19 W., Sec. 31, NW¼NW¼NW¼
Kingfisher
T. 13 N., R. 19 W., Sec. 31, NE¼SW¼NW¼
Balance Rock Cove
T. 13 N., R. 19 W., Sec. 31, SE¼NE¼NW¼
Frog Point
T. 13 N., R. 19 W., Sec. 31, SE¼SE¼NW¼
Friendly Island 1, 2, 3
T. 13 N., R. 19 W., Sec. 31, NE¼NE¼SW¼
Friendly Island 4
T. 13 N., R. 19 W., Sec. 31, SE¼NE¼SW¼
Friendly Island 5
T. 13 N., R. 19 W., Sec. 31, SW¼NE¼SW¼
Goose Bay 1 & 2
T. 13 N., R. 19 W., Sec. 31, SE¼NE¼SW¼
Pilot Rock 1 & 2
T. 12 N., R. 20 W., Sec. 1, SE¼NE¼NE¼
Sand Isle 4
T. 12 N., R. 19 W., Sec. 15, NE¼SW¼SW¼
Standard Wash 1
T. 12 N., R. 19 W., Sec. 15, SW¼SE¼SW¼
Standard Wash 2 & 3
T. 12 N., R. 19 W., Sec. 22, SE¼NW¼NE¼
Standard Wash 4 & 5
T. 12 N., R. 19 W., Sec. 22, NW¼SW¼NE¼
Standard Wash 6
T. 12 N., R. 19 W., Sec. 22, SE¼NE¼NW¼
Echo Cove 1, 2, & 3
T. 12 N., R. 19 W., Sec. 23, SW¼NW¼SW¼
Echo Cove 4
T. 12 N., R. 19 W., Sec. 23, SE¼NW¼SW¼
Coyote Cove 1 & 2
T. 12 N., R. 19 W., Sec. 23, SE¼NE¼SW¼
BLM 1
T. 12 N., R. 19 W., Sec. 23, SW¼NW¼SE¼
BLM 2
T. 12 N., R. 19 W., Sec. 23, NW¼NW¼SE¼
Whyte's Retreat 1 & 2
T. 12 N., R. 18 W., Sec. 32, SW¼SW¼NW¼
Rocky Landing 1
T. 12 N., R. 18 W., Sec. 32, NW¼NW¼SW¼
Rocky Landing 2 & 3
T. 12 N., R. 18 W., Sec. 32, SE¼NW¼SW¼
Rocky Landing 4
T. 12 N., R. 18 W., Sec. 32, NE¼SW¼SW¼
Satellite Cove 1 & 2
T. 12 N., R. 18 W., Sec. 32, NE¼SE¼SW¼
Satellite Cove 3
T. 12 N., R. 18 W., Sec. 32, SE¼SE¼SW¼
Satellite Cove 4
T. 12 N., R. 18 W., Sec. 32, NW¼SE¼SW¼
Hum Hum Cove 1 & 2
T. 12 N., R. 18 W., Sec. 32, SE¼SE¼SW¼
Cove of the Little Foxes
T. 12 N., R. 18 W., Sec. 32, SE¼SE¼SW¼
Disneyland 1 & 2
T. 11 N., R. 18 W., Sec. 5, NW¼NW¼NE¼
Disneyland 3 & 4
T. 11 N., R. 18 W., Sec. 5, NE¼NW¼NE¼
Gnat Keys 1 & 2
T. 11 N., R. 18 W., Sec. 5, NE¼SW¼NW¼
Gnat Keys 3
T. 11 N., R. 18 W., Sec. 4, SE¼NW¼SW¼
Gnat Keys 4
T. 11 N., R. 18 W., Sec. 4, NE¼SW¼SW¼
Bass Isle
T. 11 N., R. 18 W., Sec. 4, SW¼NE¼SW¼
Hi Isle 1
T. 11 N., R. 18 W., Sec. 4, SW¼SE¼SW¼
Hi Isle 2, 3, 4, 5, 6, & 7
T. 11 N., R. 18 W., Sec. 9, NW¼NE¼NW¼
Hi Isle 8, 9, 10, 11 & 12
T. 11 N., R. 18 W., Sec. 9, SW¼NE¼NW¼
Hi Isle 13
T. 11 N., R. 18 W., Sec. 9, NE¼NE¼NW¼
Hi Isle 14 & 15
T. 11 N., R. 18 W., Sec. 9, SW¼NE¼NW¼
Big Horn 1, 2, 3, 4, & 5
T. 11 N., R. 18 W., Sec. 9, NE¼SE¼NW¼
Big Horn 6
T. 11 N., R. 18 W., Sec. 9, SE¼SW¼NE¼
Bass Bay 1, 2, & 3
T. 11 N., R. 18 W., Sec. 9, SW¼SW¼NE¼
Larned Landing 1, 2, & 3
T. 11 N., R. 18 W., Sec. 9, NW¼NW¼SE¼
Larned Landing 4 & 5
T. 11 N., R. 18 W., Sec. 9, SE¼NW¼SE¼
Bill Williams 1 & 2
T. 11 N., R. 18 W., Sec. 9, SW¼NE¼SE¼
Bill Williams 3
T. 11 N., R. 18 W., Sec. 9, NW¼NE¼SE¼
Bill Williams 4 & 5
T. 11 N., R. 18 W., Sec. 10, NE¼NW¼SW¼

Supplemental Rules

The following are supplemental rules for the designated shoreline campsites on the public lands described above. These special rules are in addition to existing rules and regulations that apply to all public lands as previously established in 43 Code of Federal Regulations (CFR) as well as other Federal laws applicable to the use of public lands.

Recreation Use Permit

A use permit is required for any use of the designated camp site, including occupying a campsite for any length of time. The mooring of any watercraft or floating platform offshore in the vicinity or cove of any campsite be will be considered an occupation of the campsite and will require the purchase of a permit.

The fee for a use permit will be in accordance with the fee schedule, requirements, and procedures established under the Recreation Fee Demonstration Pilot program, and are payable in U.S. funds only.

Permit receipts must be displayed or presented upon demand to the authorized BLM officer inspecting the site. Should the occupants be away from camp, the receipt must be visibly displayed in a conspicuous place.

Permits may not be reassigned or transferred between individuals and/or camp sites.

An authorized BLM officer may revoke, without reimbursement, any permit when the permittee (or permittees) violates any BLM rule or

regulation. Any permittee (or permittees) whose permit is revoked must remove all property and leave the campsite within 1 hour of notice.

Site Occupation

A camp site is considered occupied after the appropriate permit fee has been paid and the permittee has taken possession of the site by leaving personal property at the site.

No person will occupy a camp site in violation of instructions from a BLM official or when there is reason to believe that the unit is occupied by another camper. No person(s), other than authorized personnel during the commission of their duties, will occupy a permitted camp site without the consent of the permittee.

Campsites must not be left unoccupied overnight.

A single vessel and the occupants thereof may occupy only one site.

Quiet Hours

Quiet hours are from 10 p.m. to 6 a.m. in accordance with applicable state time zone standards.

Wood Collection

Cutting or collecting any firewood is prohibited, including dead and down wood and all other vegetative material.

Mooring

The mooring of vessels to vegetation, signs, cabanas, tables, grills or fire rings, toilets, trash receptacles, or other structures not designed for such use is prohibited.

Glass Containers

No person will have in their possession glass or ceramic food or beverage containers of any type while occupying a shoreline campsite.

Firearms

The discharge or use of firearms or weapons is prohibited inside or within ½ mile of any occupied campsite.

Sanitation

Persons using a campsite must keep their site free of litter and trash during the period of occupancy and remove all personal equipment and clean their sites upon departure.

Persons bringing or allowing pets in camp areas will be responsible for proper removal and disposal, in sanitary facilities, of any waste produced by these animals.

Alcoholic Beverages

The following are prohibited:

—The sale or gift of an alcoholic beverage to a person less than 21 years of age.

—The possession of an alcoholic beverage by a person less than 21 years of age.

—The consumption of an alcoholic beverage by a person less than 21 years of age.

Authority and Penalties

This notice is published under the authority of Title 43, Code of Federal Regulations, Subpart 8365, Section 1–6. Violations are punishable as Class A misdemeanors.

Dated: May 15, 1998.

Lonna M. O'Neal.

Acting State Director, Arizona.

[FR Doc. 98–13515 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–32–M

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[NM–952–08–1420–00]

Filing of Plat of Survey; New Mexico

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice.

SUMMARY: The plats of survey described below will be officially filed in the New Mexico State office, Bureau of Land Management, Santa Fe, New Mexico, on June 11, 1998.

New Mexico Principal Meridian, New Mexico

T. 13 N., R. 11 E., accepted May 8, 1998, for Group 921 NM;
Supplemental Plat for T. 10 N., Range 4 East.

If a protest against a survey, as shown on any of the above plats is received prior to the date of official filing, the filing will be stayed pending consideration of the protest. A plat will not be officially filed until the day after all protests have been dismissed and become final or appeals from the dismissal affirmed.

A person or party who wishes to protest against any of these surveys must file a written protest with the NM State Director, Bureau of Land Management, stating that they wish to protest.

A statement of reasons for a protest may be filed with the notice of protest to the State Director, or the statement of reasons must be filed with the State Director within thirty (30) days after the protest is filed.

Failure to submit the statement of reasons may result in dismissal of the protest.

The above-listed plats represent dependent resurveys, surveys, and subdivisions.

These plats will be in the New Mexico State Office, Bureau of Land Management, P.O. Box 27115, Santa Fe, New Mexico 87502–0115. Copies may be obtained from this office upon payment of $1.10 per sheet.

Dated: May 11, 1998.

John P. Bennett,

Chief Cadastral Surveyor for New Mexico.

[FR Doc. 98–13573 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–FB–M

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[WY–989–1050–00–P]

Filing of Plats of Survey; Wyoming

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice.

SUMMARY: The plats of survey of the following described lands are scheduled to be officially filed in the Wyoming State Office, Cheyenne, Wyoming, thirty (30) calendar days from the date of this publication.

Sixth Principal Meridian, Wyoming

T. 41 N., R. 60 W., accepted May 12, 1998
T. 58 N., R. 60 W., accepted May 12, 1998
T. 38 N., R. 74 W., accepted May 12, 1998
T. 20 N., R. 112 W., accepted May 12, 1998

Sixth Principal Meridian, Nebraska

T. 24 N., R. 9 E., accepted May 12, 1998
T. 25 N., R. 9 E., accepted May 12, 1998

If protests against a survey, as shown on any of the above plats, are received prior to the official filing, the filing will be stayed pending consideration of the protest(s) and or appeal(s). A plat will not be officially filed until after disposition of protest(s) and or appeal(s).

These plats will be placed in the open files of the Wyoming State Office, Bureau of Land Management, 5353 Yellowstone Road, Cheyenne, Wyoming, and will be available to the public as a matter of information only. Copies of the plats will be made available upon request and prepayment of the reproduction fee of $1.10 per copy.

A person or party who wishes to protest a survey must file with the State Director, Bureau of Land Management, Cheyenne, Wyoming, a notice of protest prior to thirty (30) calendar days from the date of this publication. If the protest notice did not include a statement of reasons for the protest, the protestant shall file such a statement with the State Director within thirty (30) calendar days after the notice of protest was filed.

The above-listed plats represent dependent resurveys, subdivision of sections.

FOR FURTHER INFORMATION CONTACT: Bureau of Land Management, P.O. Box 1828, 5353 Yellowstone Road, Cheyenne, Wyoming 82003.

Dated: May 12, 1998.

John P. Lee,

Chief, Cadastral Survey Group.

[FR Doc. 98–13596 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–22–M

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[NV–930–1430–00; N–62533]

Proposed Withdrawal and Opportunity for Public Meeting; Nevada

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice.

SUMMARY: The Department of the Army, Corps of Engineers, has filed an application (N–62533) to withdraw 2,243.20 acres of public land in Clark County, Nevada, to be used by the Nevada National Guard for military training. This notice closes the land for up to 2 years from surface entry and mining.

DATES: Comments and requests for meeting should be received on or before August 19, 1998.

ADDRESSES: Comments and meeting requests should be sent to the Nevada State Director, BLM, 1340 Financial Blvd., P.O. Box 12000, Reno, Nevada 89520.

FOR FURTHER INFORMATION CONTACT: Dennis J. Samuelson, BLM Nevada State Office, 702–861–6532.

SUPPLEMENTARY INFORMATION: On April 17, 1998, the Department of the Army, Los Angeles District, Corps of Engineers, filed an application to withdraw the following described public land from settlement, sale, location, or entry under the general land laws, including the mining laws, subject to valid existing rights:

Mount Diablo Meridian

T. 19 S., R. 62 E.,
Sec. 5, lots 1 to 4, inclusive, S½N½, and S½;
Sec. 8, W½;
Secs. 16 and 17.

The area described contains 2,243.24 acres in Clark County.

The purpose of the proposed withdrawal is for use by the Nevada National Guard for military training. Training will consist of land navigation by soldiers on foot, wheeled and tracked vehicles on existing roads, eye safe laser sighting of targets, and tank crew proficiency course. No live fire will be allowed. The land described above was formerly used by the U.S. Air Force as part of the Nellis Small Arms Range.

For a period of 90 days from the date of publication of this notice, all persons who wish to submit comments, suggestions, or objections in connection with the proposed withdrawal may present their views in writing to the Nevada State Director of the Bureau of Land Management.

Notice is hereby given that an opportunity for a public meeting is afforded in connection with the proposed withdrawal. All interested persons who desire a public meeting for the purpose of being heard on the proposed withdrawal must submit a written request to the Nevada State Director within 90 days from the date of publication of this notice. Upon determination by the authorized officer that a public meeting will be held, a notice of the time and place will be published in the **Federal Register** at least 30 days before the scheduled date of the meeting.

The application will be processed in accordance with the regulations set forth in 43 CFR Part 2300.

For a period of 2 years from the date of publication of this notice in the **Federal Register**, the lands will be segregated as specified above unless the application is denied or canceled or the withdrawal is approved prior to that date. Other uses which will be permitted during this segregative period are rights-of-way, leases, and permits.

The temporary segregation of the land in connection with a withdrawal application shall not affect administrative jurisdiction over the land, and the segregation shall not have the effect of authorizing any use of the land by the Corps of Engineers.

Dated: May 12, 1998.

William K. Stowers,

Lands Team Lead.

[FR Doc. 98–13585 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–HC–P

DEPARTMENT OF THE INTERIOR

Minerals Management Service

Agency Information Collection Activities: Submitted for Office of Management and Budget Review; Comment Request

Title: Report of Sales and Royalty Remittance, Form MMS–2014.

OMB Control Number: 1010–0022.

Comments: This collection of information has been submitted to the Office of Management and Budget (OMB) for approval. In compliance with the Paperwork Reduction Act of 1995, Section 3506(c)(2)(A), we are notifying you, members of the public and affected agencies, of this collection of information, and are inviting your comments. Is this information collection necessary for us to properly do our job? Have we accurately estimated the public's burden for responding to this collection? Can we enhance the quality, utility, and clarity of the information we collect? Can we lessen the burden of this information collection on the respondents by using automated collection techniques or other forms of information technology?

Comments should be made directly to the Attention: Desk Officer for the Interior Department, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB Control Number: 1010–0022), Washington, DC 20503; telephone (202) 395–7340. Copies of these comments should also be sent to us. The U.S. Postal Service address is Minerals Management Service, Royalty Management Program, Rules and Publications Staff, P.O. Box 25165, MS 3021, Denver, Colorado 80225–0165; the courier address is Building 85, Room A–613, Denver Federal Center, Denver, Colorado 80225; and the e-Mail address is RMP.comments@mms.gov. OMB has up to 60 days to approve or disapprove the information collection but may respond after 30 days; therefore, public comments should be submitted to OMB within 30 days in order to assure their maximum consideration.

Copies of the proposed information collection and related explanatory material may be obtained by contacting Dennis C. Jones, Rules and Publications Staff, telephone (303) 231–3046, FAX (303) 231–3385, e-Mail Dennis.C.Jones@mms.gov.

DATES: Written comments should be received on or before June 22, 1998.

SUMMARY: The Secretary of the Interior is responsible for the collection of royalties from leases producing minerals from leased Federal and Indian lands. The Secretary is required by various laws to manage the production of mineral resources on Indian lands and Federal onshore and offshore leases, to collect the royalties due, and to distribute the funds in accordance with those laws.

The Minerals Management Service (MMS) performs the royalty management function for the Secretary. When a company or individual enters

into a contract to develop, produce, and dispose of minerals from Federal or Indian lands, that company or individual agrees to pay the United States or Indian tribe or allottee a share (royalty) monthly of the full value received for the minerals taken from leased lands.

The Auditing and Financial System (AFS) is the automated fiscal accounting system used by the Royalty Management Program (RMP) to account for revenues collected from Federal and Indian leases. The Report of Sales and Royalty Remittance, Form MMS–2014, is the only document used for reporting royalties, certain rents, and other lease-related transactions to MMS. AFS relies on data reported by payors on Form MMS–2014 for the majority of its processing.

In addition to accounting for royalties reported by payors, AFS, using Form MMS–2014 information, performs numerous other functions. These functions include monthly distribution of mineral revenues to State, Indian, and U.S. Treasury accounts; providing royalty accounting and statistical information to States, Indians, and others who have a need for such information; and identifying under reporting and nonreporting so MMS can promptly collect revenues. Sales and royalty information gathered through AFS is compared with production data collected by a second MMS system, the Production Accounting and Auditing System. This comparison of reported production with reported sales provides MMS with valuable cross-check capabilities for verification of production with reported sales.

Failure to collect the information provided by Form MMS–2014 would render it impossible to ensure that MMS is collecting and disbursing the full value of royalties received from production of leased lands. Collection of royalties directly impacts the amount of funds made available to the United States Treasury, to State governments, and to Indian tribes and allottees.

Description of Respondents: Companies or individuals (payors) that contract to develop, produce, and dispose of minerals from Federal or Indian lands and agree to pay the United States, Indian tribe or allottee royalties on the full value received for minerals taken from leased lands.

Frequency of Response: Monthly.

Estimated Reporting and Recordkeeping Burden: 7 minutes per manually completed report, 2 minutes per electronically completed report, and 12 hours annually for recordkeeping.

Annual Responses: 3,300,000.

Annual Burden Hours: 189,000 hours.

Bureau Clearance Officer: Jo Ann Lauterbach (202) 208–7744.

Dated: April 22, 1998.

Lucy Querques Denett,

Associate Director for Royalty Management.

[FR Doc. 98–13474 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–MR–P

DEPARTMENT OF THE INTERIOR

Minerals Management Service

Agency Information Collection Activities: Submitted for Office of Management and Budget Review; Comment Request

Title: Stripper Royalty Rate Reduction Notification (Form MMS–4377).

OMB Control Number: 1010–0090.

Comments: This collection of information has been submitted to the Office of Management and Budget (OMB) for approval of an extension of a currently approved information collection. In compliance with the Paperwork Reduction Act of 1995, Section 3506 (c)(2)(A), we are notifying you, members of the public and affected agencies, of this collection of information, and are inviting your comments. Is this information collection necessary for us to properly do our job? Have we accurately estimated the public's burden for responding to this collection? Can we enhance the quality, utility, and clarity of the information we collect? Can we lessen the burden of this information collection on the respondents by using automated collection techniques or other forms of information technology?

Comments should be made directly to the Attention: Desk Officer for the Interior Department, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB Control Number 1010–0090), Washington, DC 20503; telephone (202) 395–7340. Copies of these comments should also be sent to us. The U.S. Postal Service address is Minerals Management Service, Royalty Management Program, Rules and Publications Staff, P.O.Box 25165, MS–3021, Denver, Colorado 80225–0165; the courier address is Building 85, Room A–613, Denver Federal Center, Denver, Colorado 80225; and the e-Mail address is RMP.comments@mms.gov. OMB has up to 60 days to approve or disapprove the information collection but may respond after 30 days; therefore, public comments should be submitted to OMB within 30 days in order to assure their maximum consideration.

Copies of the proposed information collection and related explanatory material may be obtained by contacting Dennis C. Jones, Rules and Publications Staff, telephone (303) 231–3046, FAX (303) 231–3385, e-Mail Dennis.C.Jones@mms.gov.

DATES: Written comments should be received on or before June 22, 1998.

SUMMARY: To encourage continued production, provide an incentive for enhanced oil recovery projects, discourage abandonment of properties producing less than 15 barrels of oil per well-day, and reduce the operator's expenses, the Bureau of Land Management (BLM) will grant royalty rate reductions to operators of stripper oil properties. BLM amended 43 CFR 3103.4–2 to establish the conditions under which an operator or owner of a stripper oil property can obtain a reduction in the royalty rate for a property producing less than 15 barrels of oil per well-day. The amended regulations provided instructions for calculation of royalty rates based on the property's annual production rate.

Operators are then required to notify the Minerals Management Service (MMS) of the reduced royalty rate using Form MMS–4377, Stripper Royalty Rate Reduction Notification. The form requires identification of the operator, name of the contact person, lease and agreement numbers, calculated royalty rate, current royalty rate, qualifying period, and effective date of royalty rate reduction. MMS uses the information provided on the form to update the database with accepted reduced royalty rates. The reduced royalty rate will become effective for all oil production from qualifying properties the first day of the month after MMS receives notification of the rate change.

Description of Respondents: Operators of low producing oil wells.

Frequency of Response: Annually.

Annual Recordkeeping Burden: 200 hours.

Annual Responses: 800.

Annual Burden Hours: 600 hours.

Bureau Clearance Officer: Jo Ann Lauterbach (202) 208–7744.

Dated: April 23, 1998.

Lucy Querques Denett,

Associate Director for Royalty Management.

[FR Doc. 98–13475 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–MR–P

DEPARTMENT OF THE INTERIOR

National Park Service

Jamaica Bay Unit of Gateway National Recreation Area, Brooklyn, NY; Concession Contract

AGENCY: National Park Service, Interior.

ACTION: Public Notice.

SUMMARY: Public notice is hereby given that the National Park Service proposes to award a concession contract authorizing recreational services including a golf driving range, miniature golf course, tennis courts, and baseball batting facilities for the public within Jamaica Bay Unit of Gateway National Recreation Area, Brooklyn, New York, for a period of ten (10) years from date of contract execution.

EFFECTIVE DATE: July 20, 1998.

ADDRESSES: Interested parties should contact National Park Service, Boston Support Office, Concession Management Program, 15 State Street, Boston, MA 02109–3572, ATTN: Lynne Koser, Telephone (617) 223–5209, to obtain a copy of the prospectus describing the requirements of the proposed contract. The cost for each prospectus is $50.00. Checks should be made payable to the National Park Service and sent to the above address.

SUPPLEMENTARY INFORMATION: This contract has been determined to be categorically excluded from the procedural provisions of the National Environmental Policy Act and no environmental document will be prepared.

The existing concessioner has performed its obligations to the satisfaction of the Secretary under an existing contract which expired by limitation of time on December 31, 1997, and therefore pursuant to the provisions of Section 5 of the Act of October 9, 1965 (79 Stat. 969; 16 U.S.C. 20), is entitled to be given preference in the renewal of the contract and in the negotiation of a new contract, providing that the existing concessioner submits a responsive offer (a timely offer which meets the terms and conditions of the Prospectus). This means that the contract will be awarded to the party submitting the best offer, provided that if the best offer was not submitted by the existing concessioner, then the existing concessioner will be afforded the opportunity to match the best offer. If the existing concessioner agrees to match the best offer, then the contract will be awarded to the existing concessioner.

If the existing concessioner does not submit a responsive offer, the right of preference in renewal shall be considered to have been waived, and the contract will then be awarded to the party that has submitted the best responsive offer.

The Secretary will consider and evaluate all proposals received as a result of this notice. Any proposal, including that of the existing concessioner, must be received by the Concession Management Program, not later than the sixtieth (60th) day following publication of this notice to be considered and evaluated.

Dated: May 4, 1998.

Chrysandra L. Walter,

Acting Regional Director, Northeast Region.

[FR Doc. 98–13512 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–70–M

DEPARTMENT OF THE INTERIOR

National Park Service

Golden Gate National Recreation Area and Point Reyes National Seashore Advisory Commission; Meeting Cancellation

Notice is hereby given in accordance with the Federal Advisory Committee Act that the meeting of the Golden Gate National Recreation Area and Point Reyes National Seashore Advisory Commission previously scheduled for Wednesday, May 13, 1998 in San Francisco will be canceled.

The Advisory Commission was established by Pub. L. 92–589 to provide for the free exchange of ideas between the National Park Service and the public and to facilitate the solicitation of advice or other counsel from members of the public on problems pertinent to the National Park Service systems in Marin, San Francisco and San Mateo Counties. Members of the Commission are as follows:

Mr. Richard Bartke, Chairman
Ms. Naomi T. Gray
Mr. Michael Alexander
Ms. Lennie Roberts
Mr. Trent Orr
Ms. Jacqueline Young
Mr. R. H. Sciaroni
Dr. Edgar Wayburn
Mr. Mel Lane
Ms. Amy Meyer, Vice Chair
Dr. Howard Cogswell
Mr. Jerry Friedman
Ms. Yvonne Lee
Mr. Redmond Kernan
Mr. Merritt Robinson
Mr. John J. Spring
Mr. Joseph Williams

Dated: May 6, 1998.

Len McKenzie,

Deputy Superintendent, Golden Gate National Recreation Area.

[FR Doc. 98–13513 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–70–P

DEPARTMENT OF THE INTERIOR

National Park Service

Keweenaw National Historical Park Advisory Commission Meeting

AGENCY: National Park Service, Interior.

ACTION: Notice of meeting.

SUMMARY: This notice announces an upcoming meeting of the Keweenaw National Historical Park Advisory Commission. Notice of this meeting is required under the Federal Advisory Committee Act (Pub. L. 92–463).

DATES: June 9, 1998; 8:30 a.m. until 4:30 p.m.

ADDRESSES: Keweenaw National Historical Park Headquarters, 100 Red Jacket Road (2nd floor), Calumet, Michigan 49913–0471.

The Chairman's welcome; minutes of the previous meeting; update on the general management plan; update on park activities; old business; new business; next meeting date; adjournment. This meeting is open to the public.

FOR FURTHER INFORMATION CONTACT: Superintendent, Keweenaw National Historical Park, Frank C. Fiala, PO Box 471, Calumet, Michigan 49913–0471, 906–337–3168.

SUPPLEMENTARY INFORMATION: The Keweenaw National Historical Park was established by Public Law 102–543 on October 27, 1992.

Dated: May 4, 1998.

William W. Schenk,

Regional Director, Midwest Region.

[FR Doc. 98–13514 Filed 5–20–98; 8:45 am]

BILLING CODE 4310–70–P

DEPARTMENT OF LABOR

Office of the Secretary

Submission for OMB Review; Comment Request

May 18, 1998.

The Department of Labor (DOL) has submitted the following public information collection requests (ICRs) 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 each individual ICR, with applicable supporting documentation, may be obtained by calling the Department of Labor, Departmental Clearance Officer, Todd R. Owen ((202) 219–5096 ext. 143) or by E-Mail to Owen-Todd@dol.gov. Individuals who use a

telecommunications device for the deaf (TTY/TDD) may call (202) 219–4720 between 1:00 p.m. and 4:00 p.m. Eastern time, Monday–Friday.

Comments should be sent to Office of Information and Regulatory Affairs, Attn: OMB Desk Officer for BLS, DM, ES, ETA, MSHA, OSHA, PWBA, or VETS, Office of Management and Budget, Room 10325, 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:

- Evaulate 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 response.

Agency: Employment and Training Administration.

Title: Planning Guidance and Instructions for Submission of Annual State Plans for FY 1999 Welfare-to-Work Formula Grants.

OMB Number: 1205–NEW.

Frequency: On occasion.

Affected Public: State, Local or Tribal Government.

Number of Respondents: 54.

Total Responses: 54.

Estimated Time Per Respondent: 10 hours.

Total Burden Hours: 540 hours.

Total annualized capital/startup costs: –0–.

Total annual costs (operating/maintaining systems or purchasing services): –0–.

Description: The Balanced Budget Act of 1997, signed by the President on August 5, 1997, authorizes the Department of Labor to provide Welfare-to-Work (WtW) grants to States and local communities to provide transitional employment assistance to move Temporary Assistance for Needy Families (TANF) recipients with significant employment barriers into unsubsidized jobs providing long-term employment opportunities. WtW funds will be provided through formula grants to States, grants to Indian tribes and competitive grants to public and private entities. This planning guidance addresses the requirements necessary for States' plans to received the formula grant funds in fiscal year 1999. Separate guidance will be issued for both the grants to Indian tribes and the competitive grants.

Agency: Employment and Training Administration.

Title: Welfare-to-Work Competitive Grants: Solicitation for Grant Applications.

OMB Number: 1205–0387.

Form Number: ETA 9070.

Frequency: On occasion.

Affected Public: State, Local or Tribal Government, Not-for-profit institutions, Business or other for-profit.

Number of Respondents: 600.

Total Responses: 600.

Estimated Time Per Respondent: 20 hours.

Total Burden Hours: 12,000.

Total annualized capital/startup costs: –0–

Total annual costs (operating/maintaining systems or purchasing services): 480,000.

Description: The Balanced Budget Act of 1997 authorized the Department of Labor to provide Welfare-to-Work (WtW) grants which include both formula grants to States and localities, and competitive grants local communities. These grants are intended to help support achievement of the welfare reform goals within the Personal Responsibility and Work Reconciliation Act (PRWORA) of 1996. Under the WtW grants programs, approximately 25% of funds not allocated by the formula grants (to States and localities) will be awarded directly to the local governments, Private Industry Councils (PICs), political subdivisions and private entities. Those private entities who apply must submit an application in conjunction with the applicable PIC or political subdivision and in consultation with the Governor.

ETA Form 9070, to be submitted by all applications for WtW competitive grant funds, provides a one-page synopsis of each project, including organizational type, contact information, service area and characteristics, areas of special interest to the Department that will be addressed by the proposed project, and proposed outcomes.

Todd R. Owen,

Departmental Clearance Officer.

[FR Doc. 98–13623 Filed 5–20–98; 8:45 am]

BILLING CODE 4510–30–M

DEPARTMENT OF LABOR

Employment and Training Administration

Proposed Information Collection Request Submitted for Public Comment and Recommendations; Attestations by Employers Using Alien Crewmembers for Longshore Activities at Locations in the State of Alaska

AGENCY: Employment and Training Administration, Labor.

ACTION: Notice.

SUMMARY: The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden conducts a preclearance consultation program to provide the general public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA95), 44 U.S.C. 3506(c)(2)(A). This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed. Currently, the Employment and Training Administration is soliciting comments concerning the proposed extension to the collection of information on the Attestation by Employers Using Alien Crewmembers to Perform Longshore Work at Locations in the State of Alaska. A copy of the proposed information collection request (ICR) can be obtained by contacting the office listed below in the addressee section of this notice.

DATES: Written comments must be submitted to the office listed in the addressee section below on or before July 20, 1998.

The Department of Labor is particularly interested in comments which:

- Evaluate whether the proposed information collection 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 collections techniques or other forms of information, e.g., permitting electronic submissions of responses.

ADDRESSES: Comments and questions regarding the collection of information on Form ETA 9033–A, Attestation by Employers Using Alien Crewmembers for Longshore Activities in the State of Alaska, should be directed to James Norris, Chief, Division of Foreign Labor Certifications, U.S. Department of Labor, 200 Constitution Avenue, NW., Room N–4456, Washington, DC 20210 ((202) 219–5263 (this is not a toll-free number)).

SUPPLEMENTARY INFORMATION:

I. Background

The information collection is required due to amendments to section 258 of the Immigration and Nationality Act (8 U.S.C. 1101 *et seq.*) (INA). The amendments created an Alaska exception to the general prohibition on the performance of longshore work by alien crewmembers in U.S. ports. Under the Alaska exception, before any employer may use alien crewmembers to perform longshore work in the State of Alaska, it must submit an attestation to ETA containing the elements prescribed by the INA.

The INA further requires that the Department make available for public examination in Washington, DC, a list of employers which have filed attestations, and for each such employer, a copy of the employer's attestation and accompanying documentation it has received.

II. Current Actions

In order for the Department to meet its statutory responsibilities under the INA there is a need for an extension of an existing collection of information pertaining to employers' seeking to use alien crewmembers to perform longshore activities at locations in the State of Alaska.

Type of Review: Extension of a currently approved collection without change.

Agency: Employment and Training Administration, Labor.

Title: Attestations by Employers Using Alien Crewmembers for Longshore Activities at Locations in the State of Alaska.

OMB Number: 1205–0352.

Affected Public: Businesses or other for-profit.

Form: Form ETA 9033–A.

Total Respondents: 350.

Frequency of Response: Annually.

Total Response: 350.

Average Burden Hours Per Response: 3.

Estimate Total Annual Burden Hours: 1,050.

Comments submitted in response to this notice will be summarized and/or included in the request for Office of Management and Budget approval of the information collection request; they will also be become a matter of public record.

Signed at Washington DC this 15th day of May, 1998.

John R. Beverly, III,

Director, U.S. Employment Service.

[FR Doc. 98–13619 Filed 5–20–98; 8:45 am]

BILLING CODE 4510–30–M

DEPARTMENT OF LABOR

Employment and Training Administration

Proposed Information Collection Request Submitted for Public Comment and Recommendations: Labor Condition Applications and Requirements for Employers Using Nonimmigrants on H–1B Visas in Specialty Occupations and as Fashion Models

AGENCY: Employment and Training Administration, Labor.

ACTION: Notice.

SUMMARY: The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden conducts a preclearance consultation program to provide the general public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA95), 44 U.S.C. 3506(c)(2)(A). This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed. Currently, the Employment and Training Administration is soliciting comments concerning the proposed extension to the collection of information on the Labor Condition Application for H–1B nonimmigrants. A copy of the proposed information collection request (ICR) can be obtained by contacting the office listed below in the **ADDRESSE** section of this notice.

DATES: Written comments must be submitted to the office listed in the **ADDRESSE** section below on or before July 20, 1998.

The Department of Labor is particularly interested in comments which:

◀ Evaluate whether the proposed information collection 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 collections techniques or other forms of information, e.g., permitting electronic submissions of responses.

ADDRESSES: Comments and questions regarding the collection of information on Form ETA 9035, Labor Condition Application for H–1B Nonimmigrants, should be directed to James Norris, Chief, Division of Foreign Labor Certifications, U.S. Department of Labor, 200 Constitution Avenue, NW., Room N–4456, Washington, D.C. 20210 ((202) 219–5263 (this is not a toll-free number)).

SUPPLEMENTARY INFORMATION:

I. Background

The Immigration and Naturalization Act (INA) requires that before any alien may be admitted or otherwise provided status as an H–1B nonimmigrant, the prospective employer must have filed with the Department a labor condition application stating that they will offer prevailing wages and working conditions, that there is not a strike or lockout in the course of a labor dispute in the occupational classification at the place of employment, and that they have provided notice of such filing to the bargaining representative or, if there is none, by positing notice of filing in conspicuous locations at the place of employment. Further, the employer must make certain documentation available for public examination. Complaints may be filed with the Department alleging a violation of the labor condition application process. If reasonable cause is found to believe a violation has been committed, the Department will conduct an investigation and, if appropriate, assess penalties. The INA places a limit of

65,000 per year on the number of aliens who can be admitted to the U.S. on H–1B visas and further limits these workers to a maximum of six years duration of stay under H–1B status.

The INA requires that the Department make available for public examination in Washington, DC, a list of employers which have filed labor condition applications.

II. Current Actions

In order for the Department to meet its statutory responsibilities under the INA there is a need for an extension of an existing collection of information pertaining to employers' seeking to use H–1B nonimmigrants in specialty occupations or as fashion models of distinguished merit and ability. There is an increase in burden due to a sustained increase in the number of labor condition applications filed by employers each year.

Type of Review: Extension of a currently approved collection without change.

Agency: Employment and Training Administration, Labor.

Title: Labor Condition Applications and Requirements for Employers Using Nonimmigrants on H–1B Visas in Specialty Occupations and as Fashion Models.

OMB Number: 1205–0310.

Affected Public: Businesses or other for-profit; not-for-profit institutions; Federal government; State, Local or Tribal government.

Form: Form ETA 9035.

Total Respondents: 250,000.

Frequency of Response: On occasion.

Total Responses: 250,050.

Average Burden Hours Per Response: 1.25.

Estimate Total Annual Burden Hours: 250,050.

Comments submitted in response to this notice will be summarized and/or included in the request for Office of Management and Budget approval of the information collection request; they will also be become a matter of public record.

Signed at Washington D.C. this 15th day of May, 1998.

John R. Beverly III,

Director, U.S. Employment Service.

[FR Doc. 98–13620 Filed 5–20–98; 8:45 am]

BILLING CODE 4510–30–M

DEPARTMENT OF LABOR

Mine Safety and Health Administration

Proposed Information Collection Request Submitted for Public Comment and Recommendations; Escape and Evacuation Plan

ACTION: Notice.

SUMMARY: The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden conducts a preclearance consultation program to provide the general public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA95) [44 U.S.C. 3506(c)(2)(A)]. This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed.

Currently, the Mine Safety and Health Administration (MSHA) is soliciting comments concerning the proposed extension of the information collection related to the Escape and Evacuation. MSHA is particularly interested in comments which:

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

* Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

* Enhance the quality, utility, and clarity of the information to be collected; and

* Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submissions of responses.

A copy of the proposed information collection request can be obtained by contacting the employee listed below in the For Further Information Contact section of this notice.

DATES: Submit comments on or before July 20, 1998.

ADDRESSES: Submit comments to Patricia W. Silvey, Director, Office of Standards, Regulations, and Variances, 4015 Wilson Boulevard, Room 627, Arlington, VA 22203–1984. Commenters are encouraged to send their comments on a computer disk, or via E-mail to psilvey@msha.gov, along with an original printed copy. Ms. Silvey can be reached at (703) 235–1910 (voice) or (703) 235–5551 (facsimile).

FOR FURTHER INFORMATION CONTACT: Theresa M. O'Malley, Program Analysis Officer, Office of Program Evaluation and Information Resources, U.S. Department of Labor, Mine Safety and Health Administration, Room 719, 4015 Wilson Boulevard, Arlington, VA 22203–1984. Ms. O'Malley can be reached at tomalley@msha.gov (Internet E-mail), (703) 235–1470 (voice), or (703) 235–1563 (facsimile).

SUPPLEMENTARY INFORMATION:

I. Background

Title 30, CFR § 57.11053 requires the development of an escape and evacuation plan specifically addressing the unique conditions of each underground metal and nonmetal mine. Section 57.11053 also requires that revisions be made as mining progresses. The plan must be available to the inspector and conspicuously posted for the benefit of affected miners. The plan is required to be reviewed jointly by the operator and MSHA once every 6 months.

II. Current Actions

An accurate, up-to-date plan is vital to the safety of the miners and rescue personnel in the event of an emergency. The plans are monitored by MSHA to ensure that plans are updated as mining progresses and that the escape routes are still effective.

Type of Review: Extension.

Agency: Mine Safety and Health Administration.

Title: 30 CFR § 57.11053, *Escape and Evacuation Plans.*

OMB Number: 1219–0046.

Affected Public: Business or other for-profit institutions.

Cite/Reference/Form/etc: 30 CFR § 57.11053.

Estimated Total Burden Cost: $233,280.

Total Burden Cost (capital/startup): $0.

Total Burden Cost (operating/maintaining): $2,430.

Comments submitted in response to this notice will be summarized and/or included in the request for Office of Management and Budget approval of the information collection request; they will also become a matter of public record.

Dated: May 14, 1998.

George M. Fesak,

Director, Program Evaluation and Information Resources.

[FR Doc. 98–13621 Filed 5–20–98; 8:45 am]

BILLING CODE 4510–43–M

DEPARTMENT OF LABOR

Occupational Safety and Health Administration

[Docket Number ICR 98–7]

Agency Information Collection Activities: Proposed Collection; Comment Request; Cadmium in Construction

ACTION: Notice.

SUMMARY: The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden, conducts a preclearance consultation program to provide the general public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA95) [44 U.S.C. 3506(c)(2)(A)]. This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed. Currently the Occupational Safety and Health Administration is soliciting comments concerning the proposed extension of the information collection request for the Cadmium in Construction (29 CFR 1926.1127) standard. A copy of the proposed information collection request (ICR) can be obtained by contacting the employee listed below in the addresses section of this notice. The Department of Labor is particularly interested in comments which:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the agency, including whether the information will have practical utility;
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submissions of responses.

DATES: Written comments must be submitted by July 20, 1998.

ADDRESSES: Comments are to be submitted to the Docket Office, Docket No. ICR 98–7, U.S. Department of Labor, Room N–2625, 200 Constitution Avenue, NW, Washington, DC 20210, telephone number (202) 219–7894. Written comments limited to 10 pages or less in length may also be transmitted by facsimile to (202) 219–5046.

FOR FURTHER INFORMATION CONTACT: Adrian Corsey, Directorate of Policy, Occupational Safety and Health Administration, (OSHA), U.S. Department of Labor, Room N3627, telephone (202) 219–4690. A copy of the referenced information collection request is available for inspection and copying in the Docket Office and will be mailed immediately to persons who request copies by telephoning Adrian Corsey at (202) 219–4690 extension 144 or Barbara Bielaski at (202) 219–8076 extension 142. For electronic copies of the Information Collection Request on Cadmium in Construction, contact OSHA's WebPage on the Internet at http://www.osha-slc.gov/ and click on ''Information Collection Request''.

SUPPLEMENTARY INFORMATION:

I. Background

The Cadmium standard and its information collection requirements provide protection for employees from the adverse health effects associated with occupational exposure to cadmium. The standard requires that employers establish a compliance program, including exposure monitoring and medical records. These records are used by employees, physicians, employers and OSHA to determine the effectiveness of the employers' compliance efforts. Also the standard requires that OSHA have access to various records to ensure that employers are complying with the disclosure provisions.

Type of Review: Extension.

Agency: Occupational Safety and Health Administration.

Title: Cadmium in Construction (29 CFR 1926.1127).

OMB Control Number: 1218–0186.

Affected Public: Business or other for-profit, Federal government, State and Local governments.

Total Respondents: 10,000.

Frequency: On occasion.

Total Responses: 243,555.

Average Time per Response: Ranges from 5 minutes to maintain records to 1.5 hours for an employee to have a medical exam.

Estimated Total Burden Hours: 34,813.

Total Annualized capital/startup costs: –0–.

Total initial annual costs (operating/maintaining systems or purchasing services): $2,232,500.

Comments submitted in response to this notice will be summarized and included in the request for Office of Management and Budget approval of the information collected. The comments will become a matter of public record.

Signed at Washington, DC, this 18th day of May, 1998.

Charles N. Jeffress,

Assistant Secretary of Labor.

[FR Doc. 98–13624 Filed 5–20–98; 8:45 am]

BILLING CODE 4510–26–M

DEPARTMENT OF LABOR

Occupational Safety and Health Administration

[Docket No. ICR–98–28]

Agency Information Collection Activities; Proposed Collection; Comment Request; Logging Operations (29 CFR 1910.266)

ACTION: Notice.

SUMMARY: The Department of Labor, as part of its continuing effort to reduce paperwork and respondent burden, conducts a preclearance consultation program to provide the general public and Federal agencies with an opportunity to comment on proposed and/or continuing collections of information in accordance with the Paperwork Reduction Act of 1995 (PRA–95) (44 U.S.C. 3506(c)(2)(A)). This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and impact of collection requirements on respondents can be properly assessed. Currently, the Occupational Safety and Health Administration (OSHA) is soliciting comments concerning the proposed extension of the information collection requirements contained in the standard on Logging Operations (29 CFR 1910.266). The Agency is particularly interested in comments which:

- Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including

whether the information will have practical utility;

- Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;
- Enhance the quality, utility, and clarity of the information to be collected; and
- Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology, e.g., permitting electronic submissions of responses.

DATES: Written comments must be submitted on or before July 20, 1998.

ADDRESSES: Comments are to be submitted to the Docket Office, Docket No. ICR–98–28, Occupational Safety and Health Administration, U.S. Department of Labor, Room N–2625, 200 Constitution Avenue, N.W., Washington, D.C. 20210. Telephone: (202) 219–7894. Written comments limited to 10 pages or less in length may also be transmitted by facsimile to (202) 219–5046.

FOR FURTHER INFORMATION CONTACT: Theda Kenney, Directorate of Safety Standards Programs, Occupational Safety and Health Administration, U.S. Department of Labor, Room N–3605, 200 Constitution Avenue, NW, Washington, D.C. 20210, telephone: (202) 219–8061. A copy of the referenced information collection request is available for inspection and copying in the Docket Office and will be mailed to persons who request copies by telephoning Theda Kinney at (202) 219–8061, extension 100, or Barbara Bielaski at (202) 219–8076, extension 142. For electronic copies of the Information Collection Request on Logging Operations (29 CFR 1910.266), contact OSHA's WebPage on the Internet at http://www.osha.gov.

SUPPLEMENTARY INFORMATION:

I. Background

The Occupational Safety and Health Act of 1970 (the Act) authorizes the promulgation of such health and safety standards as are necessary or appropriate to provide safe or healthful employment and places of employment. The statute specifically authorizes information collection by employers as necessary or appropriate for the enforcement of the Act or for developing information regarding the causes and prevention of occupational injuries, illnesses, and accidents.

Section 1910.266(i)(10)(i) requires an employer to verify that employees have been trained in the safe performance of assigned work tasks, first-aid and CPR by preparing written certification records. Section 1910.266(i)(10)(ii) requires an employer to maintain the certification records.

The training certification is necessary to assure compliance with the requirement that employees have been trained in the various precautions and safe practices in logging operations. The information collected would also be used by compliance officers to determine that employees have been properly trained according to the requirements set forth in 29 CFR 1910.266(i).

II. Current Actions

This notice requests public comment on OSHA's burden hour estimates prior to OSHA seeking Office of Management and Budget (OMB) approval of the information collection requirements contained in the Logging Operations standard.

Type of Review: Extension of a Currently Approved Collection.

Agency: U.S. Department of Labor, Occupational Safety and Health Administration.

Title: Logging Operations (29 CFR 1910.266).

OMB Number: 1218–0198.

Agency Number: Docket Number ICR–98–28.

Affected Public: Business or other for-profit; State or local governments.

Number of Respondents: 86,400.

Frequency: Initially, On Occasion.

Average Time per Response: 3 minutes (0.05 hr.).

Estimated Total Burden Hours: 4,320.

Total Annualized Capital/Startup Costs: $0.

Comments submitted in response to this notice will be summarized and included in the request for Office of Management and Budget approval of the information collection request. The comments will become a matter of public record.

Signed at Washington, D.C., this 18th day of May 1998.

Charles N. Jeffress,

Assistant Secretary of Labor.

[FR Doc. 98–13625 Filed 5–20–98; 8:45 am]

BILLING CODE 4510–26–M

DEPARTMENT OF LABOR

Occupational Safety and Health Administration

Agency Information Collection Activities; Announcement of OMB Approval

AGENCY: Occupational Safety and Health Administration, Labor.

ACTION: Notice.

SUMMARY: The Occupational Safety and Health Administration (OSHA) is announcing that two collections of information have been approved by the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1995. This document announces the OMB approval numbers and expiration dates.

FOR FURTHER INFORMATION CONTACT: Helen Beall, Division of Training and Educational Programs, Office of Training and Education, Occupational Safety and Health Administration, U.S. Department of Labor, 1555 Times Drive, Des Plaines, IL 60018, telephone (847) 297–4810.

SUPPLEMENTARY INFORMATION: In the **Federal Register** of June 30, 1997, (62 FR 35234), the Agency announced its intent to request renewal of its OMB approval for the Grantee Quarterly Progress Report and for the Application for Training Grant. In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520), OMB has reinstated its approval for both information collections and assigned OMB control number 1218–0020 to the Application for Training Grant and number 1218–0100 to the Grantee Quarterly Progress Report. The approvals expire 4/30/2001. Under 5 CFR 1320.5(b), and Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless the collection displays a valid control number.

Dated: May 15, 1998.

Charles N. Jeffress,

Assistant Secretary.

[FR Doc. 98–13622 Filed 5–20–98; 8:45 am]

BILLING CODE 4510–26–M

NATIONAL INSTITUTE FOR LITERACY

Notice of Meeting

SUMMARY: This Notice sets forth the schedule and proposed agenda of a forthcoming meeting of the National Institute for Literacy Advisory Board (Board). This notice also describes the function of the Board. Notice of this meeting is required under Section

10(a)(2) of the Federal Advisory Committee Act. This document is intended to notify the general public of their opportunity to attend the meeting.

DATE AND TIME: June 4, 1998 from 9:30 AM to 5:00 PM, and June 5, 1998 from 9:30 AM to 5:00 PM.

ADDRESSES: National Institute for Literacy, 800 Connecticut Avenue, NW, Suite 200, Washington, DC 20006.

FOR FURTHER INFORMATION CONTACT: Shelly W. Coles, National Institute for Literacy, 800 Connecticut Avenue, NW, Suite 200, Washington, DC 20006. Telephone (202) 632–1507.

SUPPLEMENTARY INFORMATION: The Board is established under Section 384 of the Adult Education Act, as amended by Title I of P.L. 102–73, the National Literacy Act of 1991. The Board consists of ten individuals appointed by the President with the advice and consent of the Senate. The Board is established to advise and make recommendations to the Interagency Group, composed of the Secretaries of Education, Labor, and Health and Human Services, which administers the National Institute for Literacy (Institute). The Interagency Group considers the Board's recommendations in planning the goals of the Institute and in the implementation of any programs to achieve the goals of the Institute. Specifically, the Board performs the following functions (a) makes recommendations concerning the appointment of the Director and the staff of the Institute; (b) provides independent advice on operation of the Institute; and (c) receives reports from the Interagency Group and Director of the Institute. In addition, the Institute consults with the Board on the award of fellowships. The Board will meet in Washington, DC on June 4, 1998 from 9:30 AM to 5:00 PM, and June 5, 1998 from 9:00 AM to 5:00 PM. The meeting of the Board is open to the public. This meeting of the Institute's Advisory Board will focus on the following agenda items: recent research developments in brain development of literacy skills; the Institute's role in the area of adult literacy and learning disabilities; and recent legislative activities that impact on the Institute and the literacy field. Records are kept of all Board proceedings and are available for public inspection at the National Institute for Literacy, 800 Connecticut Avenue, NW, Suite 200, Washington, DC 20006 from 8:30 AM to 5:00 PM.

Dated: May 18, 1998.

Andrew J. Hartman,

Director, National Institute for Literacy.

[FR Doc. 98–13605 Filed 5–20–98; 8:45 am]

BILLING CODE 6055–01–M

NATIONAL SCIENCE FOUNDATION

Special Emphasis Panel in Biological Infrastructure; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Special Emphasis Panel in Biological Infrastructure.

Date & Time: June 10, 1998, 11 a.m.–6p.m. daily; June 11, 1998, 8 a.m.–1 p.m.

Place: Room 310, NSF, 4201 Wilson Boulevard, Arlington, Virginia.

Type of Meeting: Closed.

Contact Person: Dr. DeLill Nasser, Program Director, Plant Genome Research, Division of Biological Infrastructure, Room 615, NSF, 4201 Wilson Boulevard, Arlington, VA 22230, (703) 306–1439.

Purpose of Meeting: To provide advice and recommendations concerning proposals submitted to the NSF for financial support.

Agenda: To review and evaluate proposals for sequencing the Arabidopsis thaliana genome as part of the selection process for awards.

Reason for Closing: The proposals being reviewed include information of a proprietary or confidential nature, including technical information; financial data, such as salaries; and personal information concerning individuals associated with the proposals. These matters are exempt under 5 U.S.C. 552b(c)(4) and (6) of the Government Sunshine Act.

Dated: May 1, 1998.

M. Rebecca Winkler,

Committee Management Officer.

[FR Doc. 98–13633 Filed 5–20–98; 8:45 am]

BILLING CODE 7555–01–M

NATIONAL SCIENCE FOUNDATION

Special Emphasis Panel in Civil and Mechanical Systems, Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Special Emphasis Panel in Civil and Mechanical Systems (1205).

Date & Time: June 11 and 12, 1998: 8:30 a.m. to 5:00 p.m.

Place: Rooms 530 and 580, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230.

Type of Meeting: Closed.

Contact Person: Drs. Jorn Larson-Basse and Sunil Saigal, Control, Materials and Mechanics Cluster, Division of Civil and Mechanical Systems, Room 545, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA, 22230 703/306–1361 x5073 or x5069.

Purpose of Meeting: To provide advice and recommendations concerning proposals submitted to NSF for financial support.

Agenda: To review and evaluate research proposals as part of the selection process for awards.

Reason for Closing: The proposals being reviewed include information of a proprietary or confidential nature, including technical information, financial data, such as salaries, and personal information concerning individuals associated with the proposals. These matters are exempt under 5 U.S.C. 552b(c) (4) and (6) of the Government in the Sunshine Act.

Dated: May 18, 1998.

M. Rebecca Winkler,

Committee Management Officer.

[FR Doc. 98–13634 Filed 5–20–98; 8:45 am]

BILLING CODE 7555–01–M

NATIONAL SCIENCE FOUNDATION

Special Emphasis Panel in Electrical and Communications Systems; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Special Emphasis Panel in Electrical and Communications System (1196).

Date and Time: June 8–9, 1998; 8:30 a.m. to 5:00 p.m.

Place: Room 530, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230.

Type of Meeting: Closed.

Contact Persons: Dr. Kishan Baheti, Program, Director, Knowledge Modeling and Computational Intelligence (KMCI), Division of Electrical and Communications Systems, National Science Foundations, 4201 Wilson Boulevard, Room 675, Arlington, VA 22230, Telephone: (703) 306–1339.

Purpose: To provide advice and recommendations concerning proposals submitted to NSF for financial support.

Agenda: To review and evaluate research proposals in the Knowledge Modeling and Computational Intelligence program as part of the selection process for awards.

Reason for Closing: The proposals being reviewed include information of a proprietary or confidential nature, including technical and information; financial data, such as salaries; and personal information concerning individuals associated with the proposals. These matters are within exemptions 4 and 6 of 5 U.S.C. 552b(c) (4) and (6) the Government in the Sunshine Act.

Dated: May 18, 1998.

M. Rebecca Winkler,

Committee Management Officer.

[FR Doc. 98–13630 Filed 5–20–98; 8:45 am]

BILLING CODE 7555–01–M

NATIONAL SCIENCE FOUNDATION

Special Emphasis Panel in Elementary, Secondary and Informal Education, Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Special Emphasis Panel in Elementary, Secondary and Informal Education (#59).

Date and Time: Thursday, June 11, 1998, 8:30 a.m. to 9:00 p.m., Friday, June 12, 1998, 8:30 a.m. to 1:00 p.m.

Place: National Science Foundation, Third Floor, 4201 Wilson Blvd., Arlington, VA 22230.

Type of Meeting: Closed.

Contact Person: Dr. Donald Jones Program Director, Local Systemic Change Through Teacher Enhancement in Science Program, Division of Elementary, Secondary and Informal Education, National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230, Telephone (703) 306–1620.

Purpose of Meeting: To provide advice and recommendations concerning proposals submitted to NSF for financial support.

Agenda: To review and evaluate Local Systemic Change Through Teacher Enhancement in Science proposals as part of the selection process for awards.

Reason for Closing: The proposals being reviewed include information of a proprietary or confidential nature including technical information, financial data such as salaries, and personal information concerning individuals associated with the proposals. These matters are within exemptions (4) and (6) of 5 U.S.C. 552b(c), (4) and (6) of the Government in the Sunshine Act.

Dated: May 18, 1998

M. Rebecca Winkler,

Committee Management Officer.

[FR Doc. 98–13635 Filed 5–20–98; 8:45 am]

BILLING CODE 7555–01–M

NATIONAL SCIENCE FOUNDATION

Committee on Equal Opportunity in Science and Engineering; Notice of Meeting

In accordance with the Federal Advisory Committee Act Public Law 92–463, as amended, the National Science Foundation announces the following meeting:

Name: Committee on Equal Opportunities in Science and Engineering (CEOSE) (1173).

Date & Time: June 9 (1:00 to 5:30 p.m.), June 10 (8:45–5:00) and June 11, 1998, (8:30–3:00).

Place: Room 1235, National Science Foundation, 4201 Wilson Blvd., Arlington, VA.

Type of Meeting: Open.

Contact Person: Darryl G. Gorman, Executive Secretary, CEOSE, National Science Foundation, 4201 Wilson Blvd., Arlington, Va. 22230. Phone (703) 306–1391.

Minutes: May be obtained from the Executive Secretary at the above address.

Purpose of Meeting: To advise NSF on policies and activities of the Foundation to encourage full participation of women, minorities, and persons with disabilities currently underrepresented in scientific, engineering, professional, and technical fields and to advise NSF concerning implementation of the provisions of the Science and Engineering Equal Opportunities Act.

Agenda

Tuesday June 9: 1:00–500 p.m.

1:00 p.m. Welcome
Meeting Rules and Etiquette
Approval of February 1998 Minutes
1:30 p.m. CEOSE biannual Congressional Report Workshop:
Review 1996 report content/recommendations and preparation process Design 1998 report:
(1) objectives; (2) format; (3) schedule; (4) assignments
5:00 p.m. Finalization of Report outline and Schedule
5:30 p.m. Adjourn for the day

Wednesday June 10: 8:45 a.m.–5:00 p.m.

8:45 a.m. Congressional Report—Widder
9:45 a.m. Break
10:00 a.m. Assistant to Deputy Director for Human Resource Development, HRD Report—Wanda Ward
10:30 a.m. Directorate Advisory Committee Liaison Reports—CEOSE Liaisons
11:00 a.m. Merit Review Criteria—David Schindel
11:30 a.m. Digital Library project—Steve Griffin
12:00 a.m. Working Lunch
1:00 p.m. Federal Agencies' Best Practices—Castro/Committee
Guest: Dr. Clifton Poodry, NIH
3:00 p.m. Capacity building workshop II (2 hours)—Jolly/Committee
5:00 p.m. Recommendations on capacity-building
5:30 p.m. Adjourn for the day

Thursday June 11: 8:30 a.m.–3:00 p.m.

8:30 a.m. Chair's report: Marilyn Suiter
9:00 a.m. Disabilities: Recommendations—Committee
10:00 a.m. Technology Display—Guest: TARGET Center, Dept. of Agriculture
11:00 a.m. Dr. Joseph Bordogna, Acting Deputy Director, NSF
1:00 p.m. Updating the ''Strategic/Functional Plan''
2:00 p.m. Planning the next meeting
3:00 p.m. Adjourn

Dated: May 18, 1998.

M. Rebecca Winkler,

Committee Management Officer.

[FR Doc. 98–13631 Filed 5–20–98; 8:45 am]

BILLING CODE 7555–01–M

NATIONAL SCIENCE FOUNDATION

NSF/DOE Nuclear Science Advisory Committee; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: NSF/DOE Nuclear Science Advisory Committee (1176).

Date and Time: June 9, 1998; 8:30 a.m. to 6:00 p.m.

Place: Argonne National Laboratory, Argonne, IL 60439.

Type of Meeting: Open.

Contact Person: Dr. Bradley Keister, Program Director for Nuclear Physics, National Science Foundation, 4201 Wilson Blvd., Arlington, VA 22230. Telephone: (703) 306–1891.

Purpose of Meeting: To present and discuss a charge concerning laboratory facilities funded by the Department of Energy.

Agenda: Presentation of the charge concerning DOE facilities (D. Kovar, DOE) Development and discussion of plan, to respond to the charge Public Comment (*).

(*) Persons wishing to speak should make arrangements through the Contact Person identified above.

Dated: May 18, 1998.

M. Rebecca Winkler,

Committee Management Officer.

[FR Doc. 98–13632 Filed 5–20–98; 8:45 am]

BILLING CODE 7555–01–M

NUCLEAR REGULATORY COMMISSION

Agency Information Collection Activities: Submission for OMB Review; Comment Request

AGENCY: Nuclear Regulatory Commission (NRC).

ACTION: Notice of the OMB review of information collection and solicitation of public comment.

SUMMARY: The NRC has recently submitted to OMB for review the following proposal for the collection of information under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35). The NRC hereby informs potential respondents that an agency may not conduct or sponsor, and that a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number.

1. Type of submission, new, revision, or extension: Extension.

2. The title of the information collection: NRC Form 314—Certificate of Disposition of Materials.

3. How often the collection is required: The form is submitted once, when a licensee terminates its license.

4. Who will be required or asked to report: Persons holding an NRC license for the possession and use of radioactive byproduct, source, or special nuclear material who are ceasing licensed activities and terminating the license.

5. The estimated number of annual respondents: 400.

6. An estimate of the total number of hours needed annually to complete the requirement or request: An average of 0.5 hours per response, for a total of 200 hours.

7. An indication of whether Section 3507(d), Public Law 104–13 applies: Not applicable.

8. Abstract: NRC Form 314 furnishes information to NRC regarding transfer or other disposition of radioactive material by licensees who wish to terminate their licenses. The information is used by NRC as part of the basis for its determination that the facility has been cleared of radioactive material before the facility is released for unrestricted use.

A copy of the final supporting statement may be viewed free of charge at the NRC Public Document Room, 2120 L Street, NW (lower level), Washington, DC. OMB clearance requests are available at the NRC worldwide web site (http://www.nrc.gov) under the FedWorld collection link on the home page tool bar. The document will be available on the NRC home page site for 60 days after the signature date of this notice.

Comments and questions should be directed to the OMB reviewer by June 22, 1998: Erik Godwin, Office of Information and Regulatory Affairs (3150–0028), NEOB–10202, Office of Management and Budget, Washington, DC 20503.

Comments can also be submitted by telephone at (202) 395–3084.

The NRC Clearance Officer is Brenda Jo. Shelton, 301–415–7233.

Dated at Rockville, Md, this 14th day of May 1998.

For the Nuclear Regulatory Commission.

Brenda Jo. Shelton,

NRC Clearance Officer, Office of the Chief Information Officer

[FR Doc. 98–13506 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 50–261]

Carolina Power and Light Co.; Notice of Consideration of Issuance of Amendment to Facility Operating License and Opportunity for a Hearing

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of an amendment to Facility Operating License DPR–23, issued to Carolina Power and Light Company (the licensee), for operation of the H.B. Robinson Steam Electric Plant (HBR), Unit 2, located in Darlington County, South Carolina.

The proposed amendment would revise the HBR Updated Final Safety Analysis Report (UFSAR) to include the evaluation of a previously unanalyzed spent fuel cask drop scenario. The scenario involves postulated drop of a loaded spent fuel shipping cask as the cask is being moved from the decontamination facility to the shipping railcar with the valve box cover removed.

Before issuance of the proposed license amendment, the Commission will have made findings required by the Atomic Energy Act of 1954 (the Act), as amended, and the Commission's regulations.

By June 19, 1998, 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 which is available at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Hartsville Memorial Library, 147 West College Avenue, Hartsville, South Carolina 29550. 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 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 and extent of the petitioner's right under the Act to be made a 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 the 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 specific 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 this 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 the 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.

A request for a hearing or 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 Adjudication Staff, or may be delivered to the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, by the above date. A copy of the petition should also be sent to the Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington DC 20555–0001, and to William D. Johnson, Vice President and Senior Counsel, Carolina Power and Light Company, Post Office Box 1551, Raleigh, North Carolina 27602, 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 on a balancing of factors specified in 10 CFR 2.714(a)(1)(i)–(v) and 2.714(d).

If a request for a hearing is received, the Commission's staff may issue the amendment after it completes its technical review and prior to the completion of any required hearing if it publishes a further notice for public comment of its proposed finding of no significant hazards consideration in accordance with 10 CFR 50.91 and 50.92.

For further details with respect to this action, see the application for amendment dated August 28, 1997, which is available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington DC and at the local public document room located at Hartsville Memorial Library, 147 West College Avenue, Hartsville, South Carolina 29550.

Dated at Rockville, Maryland this 13th day of April, 1998.

For the Nuclear Regulatory Commission.

P.T. Kuo,

Acting Director, Project Directorate II–1, Division of Reactor Projects—I/II, Office of Nuclear Reactor Regulation.

[FR Doc. 98–13503 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 50–255]

Palisades Nuclear Plant; Notice of Partial Denial of Amendment to Facility Operating License and Opportunity for Hearing

The U.S. Nuclear Regulatory Commission (the Commission) has denied a portion of a request by Consumers Energy Company (the licensee) for an amendment to Facility Operating License No. DPR–20 issued to the licensee for operation of the Palisades Nuclear Plant, located in Van Buren County, Michigan. Notice of Consideration of Issuance of this amendment was published in the **Federal Register** on September 20, 1996 (61 FR 49493).

The purpose of the licensee's amendment request was to revise the Technical Specifications to conform the administrative controls section of the Technical Specifications to the guidance of NUREG–1432, ''Standard Technical Specifications, Combustion Engineering Plants,'' and to revise associated surveillance requirements. As part of its request, the licensee proposed to revise Technical Specifications limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary. The licensee's submittal did not include sufficient information for the staff to evaluate this proposed change.

The NRC staff has concluded that a portion of the licensee's request cannot be granted. The licensee was notified of the Commission's denial of the proposed change by a letter dated May 7, 1998.

By June 22, 1998, the licensee may demand a hearing with respect to the denial described above. Any person whose interest may be affected by this proceeding may file a written petition for leave to intervene.

A request for hearing or petition for leave to intervene must be filed with the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555, Attention: Rulemakings and Adjudications Staff, or may be delivered to the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, by the above date.

A copy of any petitions should also be sent to the Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to Judd L. Bacon, Esquire, Consumers Energy Company, 212 West Michigan Avenue, Jackson, Michigan 49201, attorney for the licensee.

For further details with respect to this action, see (1) the application for amendment dated December 11, 1995, as supplemented January 18, September 3, October 2, October 18, October 25, 1996, and March 28, 1997, and (2) the Commission's letter to the licensee dated May 7, 1998.

These documents are available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Van Wylen Library, Hope College, Holland, Michigan 49423.

Dated at Rockville, MD, this 7th day of May 1998.

For the Nuclear Regulatory Commission.

Robert G. Schaaf,

Project Manager, Project Directorate III–1, Division of Reactor Projects—III/IV, Office of Nuclear Reactor Regulation.

[FR Doc. 98–13507 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 50–255]

Palisades Nuclear Plant; Notice of Partial Denial of Amendment to Facility Operating License and Opportunity for Hearing

The U.S. Nuclear Regulatory Commission (the Commission) has denied a portion of a request by Consumers Energy Company (the licensee) for an amendment to Facility Operating License No. DPR–20 issued to the licensee for operation of the Palisades Nuclear Plant, located in Van Buren County, Michigan. Notice of Consideration of Issuance of this amendment was published in the **Federal Register** on November 5, 1997 (62 FR 59915).

The purpose of the licensee's amendment request was to revise the Technical Specifications regarding inspection requirements for the reactor coolant pump (RCP) flywheels. As part of its request, the licensee proposed to revise Technical Specification 6.5.6 to apply the provisions of Surveillance Requirement 4.0.2, which permits extension of surveillance intervals by up to 25%, to the flywheel inspection program. The licensee's submittal did not include sufficient information for the staff to evaluate this proposed change.

The NRC staff has concluded that a portion of the licensee's request cannot be granted. The licensee was notified of the Commission's denial of the

proposed change by a letter dated May 15, 1998.

By June 22, 1998, the licensee may demand a hearing with respect to the denial described above. Any person whose interest may be affected by this proceeding may file a written petition for leave to intervene.

A request for hearing or petition for leave to intervene must be filed with the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555, Attention: Rulemakings and Adjudications Staff, or may be delivered to the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, by the above date.

A copy of any petitions should also be sent to the Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington, DC 20555, and to Judd L. Bacon, Esquire, Consumers Energy Company, 212 West Michigan Avenue, Jackson, Michigan 49201, attorney for the licensee.

For further details with respect to this action, see (1) the application for amendment dated January 18, 1996, as supplemented by letters dated October 1, 1997, and January 29, and April 27, 1998, and (2) the Commission's letter to the licensee dated May 15, 1998.

These documents are available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Van Wylen Library, Hope College, Holland, Michigan 49423.

Dated at Rockville, Maryland, this 15th day of May 1998.

For the Nuclear Regulatory Commission.

Robert G. Schaaf,

Project Manager, Project Directorate III–1, Division of Reactor Projects—III/IV, Office of Nuclear Reactor Regulation.

[FR Doc. 98–13557 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket Nos. 50–387 and 50–388]

Pennsylvania Power and Light Company; Notice of Consideration of Issuance of Amendment 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. NPF–14 and NPF–22 issued to Pennsylvania Power and Light Company for operation of the Susquehanna Steam Electric Station (SSES), Units 1 and 2 located in Luzerne County, Pennsylvania.

The proposed amendment would change the Technical Specifications (TS) for SSES, Units 1 and 2 to implement the provisions of Generic Letter 86–10 related to the relocation of SSES, Units 1 and 2 Fire Protection Program from the TS to a licensee controlled document, the SSES Technical Requirements Manual. This notice supersedes the previous notice published in the **Federal Register** on October 25, 1995 (60 FR 54724), in its entirety.

Before issuance of the proposed license amendment, 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 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. Involve a significant increase in the probability or consequences of an accident previously evaluated.

The proposed change relocates the provisions of the Fire Protection Program that are contained in the Technical Specifications and places them in the Technical Requirements Manual. No requirements are being added or deleted. A requirement is proposed to require written procedures for the implementation of the Technical Requirements Program. Review and approval of those portions of the Fire Protection Program contained in the Technical Requirements Manual and revisions thereto will be the responsibility of the Plant Operations Review Committee just as it was their responsibility to review changes to the fire protection Limiting Condition for Operation and Surveillance Requirements when they were part of the Technical Specifications. Requiring review by the Plant Operations Review Committee reinforces the importance of the Technical Requirements Manual and the requirements controlled by it and assures a multidisciplined review. Approved Technical Requirements or changes thereto are provided to the Susquehanna Review Committee for information. No design basis accidents are affected by the change, nor are safety systems adversely affected by the change. Therefore, there is no impact on the probability of [oc]currence or the consequences of any design basis accidents.

Approval, as defined in Technical Specification 6.8.2, of procedures listed in Technical Specification 6.8.1 is proposed to be changed from the ''Superintendent of Plant-Susquehanna'' to General Manager-Susquehanna SES. This change is administrative in nature and as such is no impact on the probability of [oc]currence or the consequences of any design basis accidents.

The proposed changes to the license conditions for Units 1 and 2 are administrative in nature in that these changes only update the listing of NRC approved safety evaluations and as such are no impact on the probability of [oc]currence or the consequences of any design basis accidents.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated.

The proposed changes relocate the provisions of the Fire Protection Program that are contained in the Technical Specifications and places them in the Technical Requirements Manual. The proposed change requires written procedures to cover the implementation of the Technical Requirements Program No requirements are being added or deleted by the Technical Requirements Manual. There are no new failure modes associated with the proposed changes. Therefore, since the plant will continue to operate as designed, the proposed changes will not modify the plant response to an accident.

Approval, as defined in Technical Specification 6.8.2, of procedures listed in Technical Specification 6.8.1 has been change[d] from the ''Superintendent of Plant Susquehanna'' to General Manager-Susquehanna SES. This change is administrative in nature and as such creates no new failure modes and will not modify the plant response to an accident.

The proposed changes to the license conditions for Units 1 and 2 are administrative in nature in that these changes only update the listing of NRC approved safety evaluations and as such create no new failure modes and will not modify the plant response to an accident.

3. Involve a significant reduction in a margin of safety.

No change is being proposed for the Fire Protection Program requirements themselves. The relevant Technical Specifications are being relocated, and the requirements contained therein are being incorporated into the Technical Requirements Manual. Plant procedures will continue to provide the specific instructions necessary for the implementation of the requirements, just as when the requirements resided in the Technical Specifications. A written procedure will be in place for the implementation of the Technical Requirements Program. Fire Protection Program changes will be subject to the provisions of 10C FR 50.59 and the current

fire protection license condition. As such, the changes do not directly affect any protective boundaries nor [do they] impact the safety limits for the boundary. Review and approval of those portions of the Fire Protection Program contained in the Technical Requirements Manual and the revisions thereto will be the responsibility of the Plant Operations Review Committee just as it was their responsibility to review changes to the fire protection Limiting Condition for Operation and Surveillance Requirements when they were part of the Technical Specification[s]. Approved Technical Requirements or changes thereto are provided to the Susquehanna Review Committee for information. Thus, there are no adverse impacts on the protective boundaries, safety limits, or margin of safety.

Since operability and surveillance requirements will remain in a controlled document, the changes do not reduce the effectiveness of Technical Specification requirements. Any changes to the Fire Protection Program requirements will be made in accordance with the provisions of 10 CFR 50.59 and the fire protection license condition.

Approval, as defined in Technical Specification 6.8.2, of procedures listed in Technical Specification 6.8.1 has been change[d] from the ''Superintendent of Plant Susquehanna'' to General Manager-Susquehanna SES. This change is administrative in nature and as such there is no adverse impact[ ] on the protective boundaries, safety limits, or margin of safety.

The proposed changes to the license conditions for Units 1 and 2 are administrative in nature in that these changes only update the listing of NRC approved safety evaluations and as such there is no adverse impacts on the protective boundaries, safety limits, or 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 amendment 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 amendment before the expiration of the 30-day notice period, provided that its final determination is that the amendment involves 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. Copies of written comments received may be examined at the NRC Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC.

The filing of requests for hearing and petitions for leave to intervene is discussed below.

By June 22, 1998, 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 which is available at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Osterhout Free Library, Reference Department, 71 South Franklin Street, Wilkes-Barre, PA 18701. 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 Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, by the above date. A copy of the petition should also be sent to the Office of the General Counsel, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, and to Jay Silberg, Esquire, Shaw, Pittman, Potts and Trowbridge, 2300 N Street NW., Washington, DC 20037, 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).

For further details with respect to this action, see the application for amendment dated May 12, 1998, which is available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Osterhout Free Library, Reference Department, 71 South Franklin Street, Wilkes-Barre, PA 18701.

Dated at Rockville, Maryland, this 15th day of May 1998.

For the Nuclear Regulatory Commission

Victor Nerses,

Senior Project Manager, Project Directorate I–2, Division of Reactor Projects—I/II, Office of Nuclear Reactor Regulation.

[FR Doc. 98–13561 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 50–352]

Philadelphia Electric Company, Limerick Generation Station, Unit 1; Notice of Issuance of Amendment To Facility Operating License

The U.S. Nuclear Regulatory Commission (the Commission) has issued Amendment No. 128 to Facility Operating License No. NPF–39, issued to Philadelphia Electric Company (the licensee), which approves installation of replacement suction strainers for operation of the Limerick Generating Station (LGS), Unit 1, located in Montgomery and Chester Counties, Pennsylvania. The amendment is effective as of the date of issuance and shall be implemented within 30 days.

The amendment documents the NRC staff's approval of the implementation of a plant modification to support the installation of replacement suction strainers for the emergency core cooling systems at the LGS, Unit 1.

The application for the amendment complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. The Commission has made appropriate findings as required by the Act and the Commission's rules and regulations in 10 CFR Chapter I, which are set forth in the license amendment.

Notice of Consideration of Issuance of Amendment to Facility Operating License and Opportunity for a Hearing in connection with this action was published in the **Federal Register** on January 29, 1998 (63 FR 4496). No request for a hearing or petition for leave to intervene was filed following this notice.

The Commission has prepared an Environmental Assessment related to the action and has determined not to prepare an environmental impact statement. Based upon the environmental assessment, the Commission has concluded that the issuance of the amendment will not have a significant effect on the quality of the human environment (63 FR 25526).

For further details with respect to the action, see (1) the application for amendment dated October 6, 1997, as supplemented by submittals dated February 2 and May 13, 1998, (2) Amendment No. 128 to License No. NPF–39, (3) the Commission's related Safety Evaluation, and (4) the Commission's Environmental Assessment. All of these items are available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street NW., Washington, DC, and at the local public document room located at the Pottstown Public Library, 500 High Street, Pottstown, PA.

Dated at Rockville, Maryland, this 14th of May 1998.

For the Nuclear Regulatory Commission.

Bartholomew C. Buckley,

Senior Project Manager, Project Directorate I–2, Division of Reactor Projects—I/II, Office of Nuclear Reactor Regulation.

[FR Doc. 98–13555 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 50–298]

Nebraska Public Power District, Cooper Nuclear Station; Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of an exemption from certain requirements of its regulations for Facility Operating License No. DRP–46 issued to Nebraska Public Power District (the licensee), for operation of Cooper Nuclear Station located in Nemaha County, Nebraska.

Environmental Assessment

Identification of Proposed Action

The proposed action would exempt Nebraska Public Power District from the requirements of 10 CFR 70.24, which require a monitoring system that will energize clear audible alarms if accidental criticality occurs in each area in which special nuclear material is handled, used, or stored. The proposed action would also exempt the licensee from the requirements to maintain emergency procedures for each area in which this licensed special nuclear material is handled, used, or stored to ensure that all personnel withdraw to an area of safety upon the sounding of the alarm, to familiarize personnel with the evacuation plan, and to designate responsible individuals for determining the cause of the alarm, and to place radiation survey instruments in accessible locations for use in such an emergency.

The proposed action is in accordance with the licensee's application for exemption dated February 23, 1998.

The Need for the Proposed Action

The purpose of 10 CFR 70.24 is to ensure that if a criticality were to occur during the handling of special nuclear

material, personnel would be alerted to that fact and would take appropriate action. At a commercial nuclear power plant the inadvertent criticality with which 10 CFR 70.24 is concerned could occur during fuel handling operations. The special nuclear material that could be assembled into a critical mass at a commercial nuclear power plant is in the form of nuclear fuel; the quantity of other forms of special nuclear material that is stored on site in any given location is small enough to preclude achieving a critical mass. Because the fuel is not enriched beyond 5.0 weight percent Uranium-235 and because commercial nuclear plant licensees have procedures and design features that prevent inadvertent criticality, the staff has determined that it is unlikely that an inadvertent criticality could occur due to the handling of special nuclear material at a commercial power reactor. The requirements of 10 CFR 70.24, therefore, are not necessary to ensure the safety of personnel during the handling of special nuclear materials at commercial power reactors.

Environmental Impacts of the Proposed Action

The Commission has completed its evaluation of the proposed action and concludes that there is no significant environmental impact if the exemption is granted. Inadvertent or accidental criticality will be precluded through compliance with the Cooper Nuclear Station Technical Specifications (TSs), the design of the fuel storage racks providing geometric spacing of fuel assemblies in their storage locations, and administrative controls imposed on fuel handling procedures. TSs requirements specify reactivity limits for the fuel storage racks and minimum spacing between the fuel assemblies in the storage racks.

Appendix A of 10 CFR part 50, ''General Design Criteria for Nuclear Power Plants,'' Criterion 62, requires the criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically-safe configurations. This is met at Cooper Nuclear Station, as identified in the TSs and the Updated Safety Analysis Report (USAR). Cooper Nuclear Station TSs Section 5.5, Fuel Storage, states that, ''The new fuel storage vault shall be such that K_{eff} dry is less than 0.90 and flooded is less than 0.95. These K_{eff} limits are satisfied by maintaining the maximum, exposure-dependent K_{∞} of the individual fuel bundles ≤1.29.'' USAR Section X–2.0, New Fuel Storage, states that, ''The new fuel racks shall be designed with sufficient spacing between the new fuel assemblies to assure that under normal conditions (dry) the fully loaded array will have a K_{eff} <0.90. Under abnormal conditions, in the event of complete flooding, the fully loaded array will have a K_{eff} <0.95. * * * The analysis, which shows that the new fuel storage vault will have a K_{eff} ≤0.90 dry and a K_{eff} <0.95 flooded, provided the maximum exposure-dependent K_{∞} ≤1.31, has been approved by the Nuclear Regulatory Commission as a part of GESTAR II.'' Note: to provide further assurance, the Technical Specifications have a more conservative limit than the USAR.

The proposed exemption would not result in any significant radiological impacts. The proposed exemption would not affect radiological plant effluents nor cause any significant occupational exposures since the Technical Specifications, design controls (including geometric spacing of fuel assembly storage spaces) and administrative controls preclude inadvertent criticality. The amount of radioactive waste would not be changed by the proposed exemption.

The proposed exemption does not result in any significant nonradiological environmental impacts. The proposed exemption involves features located entirely within the restricted area as defined in 10 CFR part 20. It does not affect non-radiological plant effluents and has no other environmental impact. Accordingly, the Commission concludes that there are no significant non-radiological environmental impacts associated with the proposed action.

Alternatives to the Proposed Action

Since the Commission has concluded that there is no measurable environmental impact associated with the proposed action, any alternatives with equal or greater environmental impact need not be evaluated. As an alternative to the proposed exemption, the staff considered denial of the requested exemption. Denial of the request would result in no change in current environmental impacts. The environmental impacts of the proposed action and the alternative action are similar.

Alternative Use of Resources

This action does not involve the use of any resources not previously considered in the ''Final Environmental Statement Related to the Operation of Cooper Nuclear Station'' dated February 1973.

Agencies and Persons Consulted

In accordance with its stated policy, on May 7, 1998, the staff consulted with Mr. John Fassell, Health Physicist, of the Nebraska Department of Health, regarding the environmental impact of the proposed action. The State official had no comments.

Finding of No Significant Impact

Based upon the environmental assessment, the Commission concludes that the proposed action will not have a significant effect on the quality of the human environment. Accordingly, the Commission has determined not to prepare an environmental impact statement for the proposed action.

For further details with respect to the proposed action, see the licensee's letter dated February 23, 1998, which is available for public inspection at the Commission's Public Document Room, which is located at The Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Auburn Memorial Library, 1810 Courthouse Avenue, Auburn, NE 68305.

Dated at Rockville, Md., this 14th day of May 1998.

For The Nuclear Regulatory Commission.

James R. Hall,

Senior Project Manager, Project Directorate IV–1, Division of Reactor Projects III/IV, Office of Nuclear Reactor Regulation.

[FR Doc. 98–13509 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 50–397]

Washington Public Power Supply System, Nuclear Project No. 2 (WNP–2); Environmental Assessment and Finding of No Significant Impact

The U.S. Nuclear Regulatory Commission (the Commission) is considering issuance of an amendment to Facility Operating License No. NPF–21 issued to Washington Public Power Supply System (the licensee), for operation of WNP–2 located in Benton County, Washington.

Environmental Assessment

Identification of the Proposed Action

The proposed action would revise the maximum yield strength for emergency core cooling system suction strainer materials listed in the WNP–2 Final Safety Analysis Report (FSAR).

The proposed action is in accordance with the licensee's application for amendment dated April 16, 1998, as supplemented by letters dated April 28 and May 8, 1998.

The Need for the Proposed Action

The proposed action is needed to support the progression to startup for WNP–2, which is currently in a refueling outage. During this outage newly designed suction strainers have been installed in the suppression pool. They are designed to protect ECCS pumps from fibrous or other material that could be transported to the suppression pool after a design basis accident such as a loss of coolant accident. The licensee determined after fabrication of these strainers that the stanless steel material had measured yield strength which exceeded the limit which was specified in the FSAR. Excessive yield strength can make the stainless steel susceptible to stress corrosion cracking (SCC) under certain environmental conditions. The licensee identified this as an unreviewed safety issue and submitted an amendment request which would change the yield strength for the installed strainers. Approval of this amendment will enable the licensee to change reactor mode and declare the strainers operable while progressing to startup and full power operation.

Environmental Impacts of the Proposed Action

The Commission has completed its evaluation of the proposed action and, based on the testing and analytical information provided by the licensee, concludes that the increase in yield strength for the specific material used in the suction strainers is acceptable. The licensee has an effective cleanup system for the suppression pool, which maintains a desired level of water cleanliness sufficient to avoid conditions that would support SCC. Further, the licensee has conducted a fracture mechanics analysis and has determined that cracking in the surface martensitic structure of the strainers will not propagate to a critical size and, thus, not jeopardize the strainers' safety related function of protecting the ECCS pumps and spray nozzles. Also, the licensee's analysis has demonstrated that the strainers have adequate structural integrity to preclude failure when the forces of design basis hydrodynamic loads are applied. Lastly, a Strauss test using actual strainer material samples demonstrated acceptable stress corrosion cracking resistance.

The staff has concluded that this change will not increase the probability or consequences of accidents, no changes are being made in the types of any effluents that may be released offsite, and there is no significant increase in the allowable offsite or occupational radiation exposure. Accordingly, the Commission concludes that there are no significant radiological environmental impacts associated with the proposed action.

With regard to potential nonradiological impacts, the proposed action does not affect nonradiological plant effluents and has no other environmental impact.

Accordingly, the Commission concludes that there are no significant environmental impacts associated with the proposed action.

Alternatives to the Proposed Action

Since the Commission has concluded there is no significant environmental impact associated with the proposed action, any alternatives with equal or greater environmental impact need not be evaluated. As an alternative to the proposed action, the staff considered denial of the proposed action. Denial of the application would result in no change in current environmental impacts. The environmental impacts of the proposed action and the alternative action are similar.

Alternative Use of Resources

This action does not involve the use of any resources not previously considered in the Final Environmental Statement for WNP–2.

Agencies and Persons Consulted

In accordance with its stated policy, on May 13, 1998, the staff consulted with the Washington State official, Mr. R. Cowley of the Department of Health, State of Washington Energy Facility Site Evaluation Council, regarding the environmental impact of the proposed action. The State official had no comments.

Finding of No Significant Impact

Based upon the environmental assessment, the Commission concludes that the proposed action will not have a significant effect on the quality of the human environment. Accordingly, the Commission has determined not to prepare an environmental impact statement for the proposed action.

For further details with respect to the proposed action, see the licensee's letter dated April 16, 1998, as supplemented by letters dated April 28, 1998, and May 8, 1998, which are available for public inspection at the Commission's Public Document Room, The Gelman Building, 2120 L Street, NW., Washington, DC, and at the local public document room located at the Richmond Public Library, 955 Northgate Street, Richland, Washington 99352.

Dated at Rockville, MD., this 14th day of May 1998.

For the Nuclear Regulatory Commission.

Chester Poslusny,

Senior Project Manager, Project Directorate IV–2, Division of Reactor Projects—III/IV, Office of Nuclear Reactor Regulation.

[FR Doc. 98–13504 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

Advisory Committee on Reactor Safeguards, Subcommittee Meeting on Thermal-Hydraulic Phenomena; Notice of Meeting

The ACRS Subcommittee on Thermal-Hydraulic Phenomena will hold a meeting on June 11–12, 1998, Room T–2B1, 11545 Rockville Pike, Rockville, Maryland.

Portions of the meeting will be closed to public attendance to discuss Westinghouse Electric Company proprietary information pursuant to 5 U.S.C. 552b(c)(4).

The agenda for the subject meeting shall be as follows:

Thursday, June 11, 1998—8:30 a.m. until the conclusion of business.

Friday, June 12, 1998—8:30 a.m. until the conclusion of business.

The Subcommittee will continue its review of the Westinghouse AP600 Test and Analysis Program (TAP) in support of the AP600 design certification. During this meeting, the Subcommittee will focus its review on the issues associated with the Westinghouse TAP for the Passive Containment System, including those identified in the February 19, 1998 ACRS letter to the NRC Executive Director for Operations. The purpose of this meeting is to gather information, analyze relevant issues and facts, and to formulate proposed positions and actions, as appropriate, for deliberation by the full Committee.

Oral statements may be presented by members of the public with the concurrence of the Subcommittee Chairman; written statements will be accepted and made available to the Committee. Electronic recordings will be permitted only during those portions of the meeting that are open to the public, and questions may be asked only by members of the Subcommittee, its consultants, and staff. Persons desiring to make oral statements should notify the cognizant ACRS staff engineer named below five days prior to the meeting, if possible, so that appropriate arrangements can be made.

During the initial portion of the meeting, the Subcommittee, along with

any of its consultants who may be present, may exchange preliminary views regarding matters to be considered during the balance of the meeting.

The Subcommittee will then hear presentations by and hold discussions with representatives of the Westinghouse Electric Company, the NRC staff, their consultants, and other interested persons regarding this review.

Further information regarding topics to be discussed, whether the meeting has been canceled or rescheduled, the scheduling of sessions which are open to the public, and the Chairman's ruling on requests for the opportunity to present oral statements and the time allotted therefor, can be obtained by contacting the cognizant ACRS staff engineer, Mr. Paul A. Boehnert (telephone 301/415–8065) between 7:30 a.m. and 4:15 p.m. (EDT). Persons planning to attend this meeting are urged to contact the above named individual one or two working days prior to the meeting to be advised of any potential changes to the agenda, etc., that may have occurred.

Dated: May 14, 1998.

Sam Duraiswamy,

Chief, Nuclear Reactors Branch.

[FR Doc. 98–13472 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 50–271]

Vermont Yankee Nuclear Power Corporation, Vermont Yankee Nuclear Power Station; Receipt of Petition for Director's Decision Under 10 CFR 2.206

Notice is hereby given that by Petition dated April 9, 1998, Mr. Michael J. Daley, on behalf of the New England Coalition on Nuclear Pollution, Inc. (or Petitioner), requested that the U.S. Nuclear Regulatory Commission (NRC) take immediate action with regard to the Vermont Yankee Nuclear Power Station. The Petitioner requests that the NRC issue an order requiring that the licensee's administrative limits, which preclude Vermont Yankee Nuclear Power Station from operating with a torus water temperature above 80 °F or with service water injection temperature greater than 50 °F, shall remain in force until certain conditions are met. The requested conditions include a complete reconstitution of the licensing basis for the maximum torus water temperature, submittal to the NRC of a technical specifications amendment request establishing the correct maximum torus water temperature, and completion of NRC review of the amendment request.

As the basis for this request, the Petitioner states that the licensee has been unable to demonstrate an ability to either justify the operational limits for the maximum torus water temperature or maintain operations within existing administrative limits (torus water temperature is critical to the proper functioning of the containment). The Petitioner also states that the NRC must move from a ''wait and see'' posture to active intervention, with immediate imposition of the order as a necessary first step.

The request is being treated pursuant to 10 CFR 2.206 of the Commission's regulations. The request has been referred to the Director of the Office of Nuclear Reactor Regulation. As provided by § 2.206, appropriate action will be taken on this petition within a reasonable time.

By letter dated May 13, 1998, the Director denied Petitioner's request for immediate action at Vermont Yankee Nuclear Power Station.

A copy of the petition is available for inspection at the Commission's Public Document Room at 2120 L Street, NW., Washington, DC. 20555–0001 and at the local public document room located at Brooks Memorial Library, 224 Main Street, Brattleboro, VT 05301.

Dated at Rockville, MD, this 13th day of May, 1998.

For the Nuclear Regulatory Commission.

Samuel J. Collins,

Director, Office of Nuclear Reactor Regulation.

[FR Doc. 98–13508 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No.: 040–07982]

Consideration of Amendment Request To Approve a Decommissioning Plan for Alliant Techsystems, Inc., and Opportunity for a Hearing

AGENCY: Nuclear Regulatory Commission.

ACTION: Notice of Intent to approve decommissioning plan license amendment and opportunity for Hearing related to source materials license for Alliant Techsystems, Inc.

The U.S. Nuclear Regulatory Commission (NRC) is considering issuance of a license amendment to Source Material License No. SUB–971, issued to Alliant Techsystems, Inc., to authorize decontamination and decommissioning activities of those areas of the licensee's Twin Cities Army Ammunition Plant, Depleted Uranium Facilities, New Brighton, Minnesota, site which require remediation prior to release for unrestricted use.

The licensee requested the amendment in a letter dated October 6, 1997. The amendment would incorporate the licensee's *Decommissioning Plan for the Twin Cities Army Ammunition Plant, Depleted Uranium Facilities, New Brighton, Minnesota.* The plan discusses the administrative and technical procedures necessary for performing the decommissioning project as follows: (1) Summary of Plan (including background, description of facilities to be remediated, etc.); (2) Choices of Decommissioning Alternatives and Decommissioning Activities (including decommissioning schedule, organization and program responsibilities); (3) Protection of Occupational and Public Health and Safety (including radiation protection, asbestos protection and waste management programs); (4) Final Radiation Safety Survey; (5) Decommissioning Cost Estimate and Funding Plan; (6) Decommissioning Quality Assurance Plan; and (7) References and Appendices.

The NRC will require the licensee to remediate the Depleted Uranium facilities to meet NRC's decommissioning criteria, and during the decommissioning activities, to maintain effluents and doses within NRC requirements and as low as reasonably achievable.

Prior to approving the decommissioning plan, NRC will have made findings required by the Atomic Energy Act of 1954, as amended, and NRC's regulations. Staff review findings and approval of the plan will be documented in an amendment to License No. SUB–971.

The NRC hereby provides notice that this is a proceeding on an application for a license amendment falling within the scope of Subpart L, Informal Hearing Procedures for Adjudications in Materials Licensing Proceedings, of the NRC's rules of practice for domestic licensing proceedings in 10 CFR part 2. Pursuant to § 2.1205(a), any person whose interest may be affected by this proceeding may file a request for a hearing in accordance with § 2.1205(d). A request for a hearing must be filed within thirty (30) days of the date of publication of this **Federal Register** Notice. The request for a hearing must be filed with the Office of the Secretary either:

1. Hand deliver to: 11555 Rockville Pike, Rockville, MD between 7:45 a.m. and 4:15 p.m., Federal workdays; or

2. Send to: Secretary, U.S. Nuclear Regulatory Commission, Washington, DC. 20555–0001, Attention: Docketing and Services Branch.

In addition to meeting other applicable requirements of 10 CFR Part 2 of the NRC's regulations, a request for a hearing filed by a person other than the applicant must describe in detail:

1. The interest of the requestor in the proceeding;

2. How that interest may be affected by the results of the proceeding, including the reasons why the requestor should be permitted a hearing, with particular reference to the factors set out in § 2.1205(h);

3. The requestor's areas of concern about the licensing activity that is the subject matter of the proceeding; and

4. The circumstances establishing that the request for a hearing is timely in accordance with § 2.1205(d).

In accordance with 10 CFR 2.1205(f), each request for a hearing must also be served, by delivering it personally or by mail, to:

1. The licensee, Alliant Techsystems, Inc., Attention: Francisco L. Lisbona III, Radiation Safety Officer, Building 502, Twin Cities Arsenal, New Brighton, MN 55112;

2. The NRC staff, by delivery to the Executive Director for Operations, One White Flint North, 11555 Rockville Pike, Rockville, MD 20852–2738; or, .

3. By mail, addressed to the Executive Director for Operations, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

For further details with respect to this action, the application for amendment request is available for inspection at the NRC's Public Document Room, 2120 L Street NW, Washington, DC 20555 or at NRC's Region III offices located at 801 Warrenville Road, Lisle, IL 60532-4351. Persons desiring to review documents at the Region III office should call Mr. George McCann at (630) 829–9856 several days in advance to assure that the documents will be readily available for review.

Dated at Lisle, Illinois, this 8th day of May 1998.

For the Nuclear Regulatory Commission.

Roy J. Caniano,

Deputy Director, Division of Nuclear Materials Safety, Region III.

[FR Doc. 98–13510 Filed 5–20–98; 8:45 am]

BILLING CODE 7590–01–P

POSTAL RATE COMMISSION

Sunshine Act Meetings

NAME OF AGENCY: Postal Rate Commission.

TIME AND DATE: 3:00 p.m., May 14, 1998.

PLACE: Commission Conference Room, 1333 H Street, NW, Suite 300, Washington, DC 20268–0001.

STATUS: Closed.

MATTERS TO BE CONSIDERED: Emergency meeting to discuss issue in Docket No. R97–1.

CONTACT PERSON FOR MORE INFORMATION: Stephen L. Sharfman, General Counsel, Postal Rate Commission, Suite 300, 1333 H Street, NW, Washington, DC 20268–0001, (202) 789–6830.

Dated: May 18, 1998.

Margaret P. Crenshaw,

Secretary.

[FR Doc. 98–13687 Filed 5–18–98; 4:41 pm]

BILLING CODE 7710–FW–M

UNITED STATES POSTAL SERVICE BOARD OF GOVERNORS

Sunshine Act Meeting

TIMES AND DATES: 1:00 p.m., Monday, June 1, 1998; 8:30 a.m., Tuesday, June 2, 1998.

PLACE: Washington, D.C., at U.S. Postal Service Headquarters, 475 L'Enfant Plaza, S.W., in the Benjamin Franklin Room.

STATUS: June 1 (Closed); June 2 (Open).

MATTERS TO BE CONSIDERED:

Monday, June 1—1:00 p.m. (Closed)

1. Briefing on Postal Rate Commission Opinion and Recommended Decision in Docket No. R97–1.
2. Corporate Credit Rating.
3. Compensation Issues.
4. Corporate Call Management.
5. Tray Management System.

Tuesday, June 2—8:30 a.m. (Open)

1. Minutes of the Previous Meeting, May 4–5, 1998.
2. Remarks of the Postmaster General/Chief Executive Officer.
3. Capital Investment.
a. 175 Next Generation Flat Sorting Machines.
4. Tentative Agenda for the June 29–30, 1998, meeting in Washington, D.C.

CONTACT PERSON FOR MORE INFORMATION: Thomas J. Koerber, Secretary of the Board, U.S. Postal Service, 475 L'Enfant Plaza, S.W., Washington, D.C. 20260–1000. Telephone (202) 268–4800.

Thomas J. Koerber,

Secretary.

[FR Doc. 98–13813 Filed 5–19–98; 3:39 pm]

BILLING CODE 7710–12–M

POSTAL SERVICE

Privacy Act of 1974, System of Records

AGENCY: Postal Service.

ACTION: Notice of new system of records.

SUMMARY: The purpose of this document is to publish notice of a new Privacy Act system of records, USPS 040.050, Customer Programs-Customer Electronic Document Preparation and Delivery Service Records. The new system contains information provided by customers who use the Postal Service's electronic-to-paper document printing and mailing service. Customers using this service electronically send a master document and mailing list to a postal control center, which electronically routes the documents to print sites for printing and mailing for Postal Service delivery.

DATES: Any interested party may submit written comments on the proposed new system of records. This proposal will become effective without further notice on June 30, 1998, unless comments received on or before that date result in a contrary determination.

ADDRESSES: Written comments on this proposal should be mailed or delivered to: Payroll Accounting/Records, United States Postal Service, 475 L'Enfant Plaza SW Rm 8831, Washington, DC 20260–5243.

Copies of all written comments will be available at the above address for public inspection and photocopying between 8 a.m. and 4:45 p.m., Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Betty Sheriff, (202) 268-2608.

SUPPLEMENTARY INFORMATION: The proposed system of records will collect information related to a new electronic-to-paper mailing and delivery service offered by the Postal Service. The service will facilitate increased use of the mail while providing a means for small-volume customers to have quality mailings promptly prepared and delivered.

Customers who use the service will create documents on their desktop computers and, using a postal icon on their computer screen, transmit that document and an associated address file through the Internet to a network

control center. The network control center electronically routes the digital documents to commercial print sites where they are printed, assembled, and entered into the mailstream for Postal Service delivery, often on the next day.

Before transmission to a print site, addresses on the list will be standardized and updated with any forwarding information that has been provided by customers. The product is a complete, correct, and standardized address that can be read by automation equipment and matched to a ZIP Code resulting in savings to the Postal Service through more effective operations and savings to the customer who has avoided duplication and remailings. Address correction is limited to notification to the customer of any addresses that are invalid and the Postal Service will not otherwise supplement or verify name or address information on the list. In providing these services, the Postal Service does not compile or disclose any mailing list.

The original list submitted by the customer will not be copied and may be returned to the customer after conversion. One copy of the converted list will be maintained under secured conditions for a period of 30 days to confirm quality handling of the order and to serve the customer who wishes to make a follow-up mailing using the same document and/or list. The list will be retained longer than 30 days or updated only at the customer's request.

System design provides for maintenance of information by the name of the customer requesting the service and not by the names of persons or entities on that customer's mailing list. The customers requesting the service will be primarily small businesses to which the Privacy Act will not apply. Nevertheless, to the extent records are covered by the Privacy Act, measures have been taken to protect them. The measures, discussed below, are intended also to ensure compliance with the Postal Reorganization Act (39 U.S.C. 412), which prohibits the Postal Service from releasing lists of the names or addresses of its customers or other persons.

Printing and mailing will be performed by commercial printers operating under a license agreement with the Postal Service. These licensees will not be maintaining records and, consequently, not operating a system of records. Nevertheless, because of the sensitive nature of the information, under the terms of a license agreement, the licensees must agree that any information received from the Postal Service in the course of the agreement must be kept in strict confidence and not disclosed to any person; must not be used by the licensee for any purpose other than to satisfy the conditions of the agreement; and must be provided with safeguards to prevent unauthorized access, disclosure, or misuse. Licensee sites will be subject to impromptu compliance inspections by the Postal Inspection Service.

Rather than apply all of its general routine uses (authorized third party disclosures) considered applicable to most Postal Service systems of records, the Postal Service has limited the application of routine uses to four situations. The first allows disclosure to the Department of Justice relative to litigation in which the Postal Service has an interest. The second allows disclosure to a law enforcement agency for criminal or civil law enforcement purposes. The third allows a disclosure to a congressperson that would occur only at the prompting of the records subject. The third allows disclosure to a contractor to perform an agency function, a disclosure that will be necessary as discussed above. Each of these is relevant and necessary to accomplish the system's purpose.

The terms of agreements with customers who use this new service will provide that the mailing lists transmitted to the Postal Service will remain the property of the customer. Consequently, routine uses within the proposed system will not apply to these lists.

Security controls have been applied to protect the information during transmission and physical maintenance. The network control center to which a customer transmits its order is housed in a Postal Service computer complex with access to the building controlled by guards, access to rooms controlled by the use of card keys, and access to systems controlled by log on identifications and passwords. Industry standard security and encryption technology will be used for Internet transmission between the customer and the network control center. Dedicated lines will be used for transmission between the network control center and the licensee. As discussed above, the terms of the license agreement will provide for the protection of information received by the licensee who will be subject to audit by the Postal Inspection Service.

For the above reasons, the Postal Service is establishing this grouping of records as a system of records subject to the Privacy Act.

Pursuant to 5 U.S.C. 552a(e)(11), interested persons are invited to submit written data, views, or arguments on this proposal. A report of the following proposed system has been sent to Congress and to the Office of Management and Budget for their evaluation.

USPS 040.050

SYSTEM NAME:

Customer Programs—Customer Electronic Document Preparation and Delivery Records, USPS 040.050.

SYSTEM LOCATION:

Marketing, Headquarters; and Information Systems Service Center, San Mateo, CA.

CATEGORIES OF INDIVIDUALS COVERED BY THE SYSTEM:

Customers who electronically request mail preparation and delivery service.

CATEGORIES OF RECORDS IN THE SYSTEM:

Name and address of customer requesting service, USPS-assigned order number, and billing information; address list provided by the customer.

AUTHORITY FOR MAINTENANCE OF THE SYSTEM:

39 U.S.C. 403, 404.

PURPOSE(S):

To promote increased use of the mail by providing electronic document preparation and mailing services for customers.

ROUTINE USES OF RECORDS MAINTAINED IN THE SYSTEM, INCLUDING CATEGORIES OF USERS AND THE PURPOSES OF SUCH USES:

Note: Mailing lists contained within this system are owned by the customer submitting the mailing list; consequently, no routine uses apply to these mailing lists.

1. Records from this system may be disclosed to the Department of Justice or to other counsel representing the Postal Service, or may be disclosed in a proceeding before a court or adjudicative body before which the Postal Service is authorized to appear, when (a) the Postal Service; or (b) any postal employee in his or her official capacity; or (c) any postal employee in his or her individual capacity whom the Department of Justice has agreed to represent; or (d) the United States when it is determined that the Postal Service is likely to be affected by the litigation, is a party to litigation or has an interest in such litigation, and such records are determined by the Postal Service or its counsel to be arguably relevant to the litigation, provided, however, that in each case, the Postal Service determines that disclosure of the records is a use of the information that is compatible with the purpose for which it was collected. This routine use specifically contemplates that information may be released in response to relevant

discovery and that any manner of response allowed by the rules of the forum may be employed.

2. When the Postal Service becomes aware of an indication of a violation or potential violation of law, whether civil, criminal, or regulatory in nature, and whether arising by general statute or particular program statute, or by regulation, rule, or order issued pursuant thereto, or in response to the appropriate agency's request on a reasonable belief that a violation has occurred, the relevant records may be referred to the appropriate agency, whether federal, state, local, or foreign, charged with the responsibility of investigating or prosecuting such violation or charged with enforcing or implementing the statute, rule, regulation, or order issued pursuant thereto.

3. Disclosure may be made to a congressional office from the record of an individual in response to an inquiry from the congressional office made at the prompting of that individual.

4. Records or information from this system may be disclosed to an expert, consultant, or other person who is under contract to the Postal Service to fulfill an agency function, but only to the extent necessary to fulfill that function. This may include disclosure to any person with whom the Postal Service contracts to reproduce, by typing, photocopy, or other means, any record for use by Postal Service officials in connection with their official duties or to any person who performs clerical or stenographic functions relating to the official business of the Postal Service.

POLICIES AND PRACTICES FOR STORING, RETRIEVING, ACCESSING, RETAINING, AND DISPOSING OF RECORDS IN THE SYSTEM:

STORAGE:

Name and address of customer will be automated during conversion and then stored off-line on magnetic media.

RETRIEVABILITY:

Postal Service-assigned job number and customer name and customer identification number.

SAFEGUARDS:

Access to these records is limited to those persons whose official duties require such access. Access to automated records is restricted by the use of encryption technology, dedicated lines, and authorized access codes. Licensees who have access to information are required by the terms of the license agreement to protect the information from unauthorized access; to limit its use to that provided by the license agreement; and to apply appropriate administrative and physical safeguards to protect the information.

RETENTION AND DISPOSAL:

Records supporting a customer order will be destroyed 30 days from completion of order, unless maintained longer at customer's request. Disposal will be by data deletion from magnetic media.

SYSTEM MANAGER(S) AND ADDRESS:

Chief Marketing Officer & Senior Vice President, United States Postal Service, 475 L'Enfant Plz SW, Washington DC 20260–2400.

NOTIFICATION PROCEDURE:

Individuals wanting to know whether information about them is maintained in this system of records must address inquiries in writing to the system manager. Inquiries must contain name, customer identification number, address, and order number, if known.

RECORD ACCESS PROCEDURES:

Requests for access must be made in accordance with the Notification Procedure above and the Postal Service Privacy Act regulations regarding access to records and verification of identity under 39 CFR 266.6.

CONTESTING RECORD PROCEDURES:

See Notification and Record Access Procedures above.

RECORD SOURCE CATEGORIES:

Information is furnished by record subjects (customers) requesting the service.

Stanley F. Mires,

Chief Counsel, Legislative.

[FR Doc. 98–13591 Filed 5–20–98; 8:45 am]

BILLING CODE 7710–12–P

RAILROAD RETIREMENT BOARD

Proposed Collection; Comment Request

SUMMARY: In accordance with the requirement of Section 3506 (c)(2)(A) of the Paperwork Reduction Act of 1995 which provides opportunity for public comment on new or revised data collections, the Railroad Retirement Board (RRB) will publish periodic summaries of proposed data collections.

Comments are invited on: (a) Whether the proposed information collection is necessary for the proper performance of the functions of the agency, including whether the information has practical utility; (b) the accuracy of the RRB's estimate of the burden of the collection of the information; (c) ways to enhance the quality, utility, and clarity of the information to be collected; and (d) ways to minimize the burden related to the collection of information on respondents, including the use of automated collection techniques or other forms of information technology.

Title and purpose of information collection: Sick Pay and Miscellaneous Payment Report; OMB 3220–0175 Under Section 6 of the Railroad Unemployment Insurance Act (RUIA) and Section 9 of the Railroad Retirement Act (RRA), the Railroad Retirement Board (RRB) maintains for each railroad employee a record of compensation paid to that employee by all railroad employers for whom the employee worked after 1936. This record, which is used by the RRB to determine eligibility for, and amount of, benefits due under the laws its administers, is conclusive as to the amount of compensation paid to an employee during such period(s) covered by the report(s) of the compensation by the railroad employer(s). Further, the Railroad Retirement Solvency Act of 1983 added subsection 1(h)(8) to the RRA which expanded the definition of compensation for purposes of computing the Tier 1 portion of an annuity to include sickness payments and certain payments other than sick pay which are considered compensation within the meaning of Section 1(h)(8). The information reporting requirements for employers are prescribed in 20 CFR 209.

To enable the RRB to establish and maintain the record of compensation, employers are required under Section 6 of the RUIA and Section 9 of the RRA to file with the RRB, in such manner and form and at such times as the RRB by rules and regulation may prescribe, reports of compensation of employees.

The RRB utilizes Form BA–10, Report of Miscellaneous Compensation and Sick Pay, to collect information regarding sick pay and certain other types of payments, referred to as miscellaneous compensation, under Section 1(h)(8) of the Railroad Retirement Act from railroad employers. In addition, the form is used by employers to report any necessary adjustments in the amounts of sick pay or miscellaneous compensation. Employers have the option of submitting the reports on the aforementioned form, or, in like format, on magnetic tape, tape cartridges or PC diskettes. Submission of the mandatory reports is requested annually. One response is required of each respondent. No changes are proposed to Form BA–10. The completion time for Form BA–10 is estimated at 55 minutes per response.

Additional Information or Comments: To request more information or to obtain a copy of the information collection justification, forms, and/or supporting material, please call RRB Clearance Officer at (312) 751–3363. Comments regarding the information collection should be addressed to Ronald J. Hodapp, Railroad Retirement Board, 844 N. Rush Street, Chicago, Illinois 60611–2092. Written comments should be received on or before July 20, 1998.

Chuck Mierzwa,

Clearance Officer.

[FR Doc. 98–13582 Filed 5–20–98; 8:45 am]

BILLING CODE 7905–01–M

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–39992; File No. SR–CBOE–98–13]

Self-Regulatory Organizations; Notice of Filing of Proposed Rule Change and Amendment No. 1 Thereto by the Chicago Board Options Exchange, Inc. Relating to the Automatic Execution of Small Retail Orders in Equity Options

May 14, 1998

Pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (''Act'')[1], notice is hereby given that on April 6, 1998, the Chicago Board Options Exchange, Inc.,(''CBOE'' 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 CBOE. On May 13, 1998, the CBOE submitted to the Commission Amendment No. 1 to the proposed rule change.[2] The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The CBOE proposes amend CBOE Rule 6.8 and Interpretation and Policy .02 thereunder to provide added flexibility to the Exchange's Retail Automatic Execution System (''RAES'') where the best bid or offer on the Exchange for a given equity option is inferior to the best bid or offer for the same option in another market where the option is traded.

The text of the proposed rule change is available at the Office of the Secretary, CBOE and at the Commission.

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 CBOE included statements concerning the purpose of and basis for the proposed rule change. The text of these statements may be examined at the places specified in Item IV below. The CBOE 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

The purpose of the proposed rule change is to provide for the automatic execution on RAES of eligible retail orders to buy or sell equity options at a price that may be one tick better than the best price currently quoted on the Exchange if the better price is then being quoted in another market where the same options are traded. Under existing CBOE Rule 6.8(a)(ii), the execution price automatically attached to an equity option order executed in RAES is the prevailing market quote on CBOE at the time the order is entered into the system. If at that same time another market is displaying a better quote for the option, under the existing Rules the order is not automatically executed, but instead, pursuant to Interpretation and Policy .02 under CBOE Rule 6.8, is rerouted for non-automated handling. In most cases, especially where the market away from the CBOE is better by only one ''tick'' (*i.e.*, by one minimum quote interval), the order is usually manually executed on CBOE at the better price.

The proposed rule change will automate the process of filing equity option orders through RAES at any better price being quoted in another market, so long as the price is better by no more than one tick. If the market away from the CBOE purports to be better than the CBOE's quoted market by more than one tick, the existing procedure will continue to apply whereby the order is rerouted out of RAES to the Designated Primary Market Maker or Order Book Official for non-automated handling.

By automating the execution of eligible retail orders for equity options in the manner described above (referred to as ''RAES Auto-Step-Up''), investors will be assured the prompt, automatic execution of these orders at the best available prices, even if those prices are being quoted in a market by more than one tick. This proposal should minimize the delay inherent in manually handling orders in this circumstance, and thereby reduce the risk to investors that, as a result of an adverse move in the market while their orders are being manually handled, they may receive an inferior execution.

The Exchange continues to believe that manual handling is called for where prices apparently quoted in other markets are more than one tick better than the Exchange's best quotes, because the quotes in other markets may be displayed in error or may otherwise not be likely to be available, and because even if Exchange market makers determine to provide an execution at such better prices, this decision should be made on a case-by-case basis by the market makers rather than automatically. In addition, the proposed rule change authorizes the Chairman of the appropriate Floor Procedure Committee or his or her designee to disable RAES Auto-Step-Up for specified classes or series of options or in respect of specified markets when such action is deemed to be warranted by circumstances or conditions applicable to such options or markets. This authority would be expected to be exercised in circumstances such as communication or system problems, fast markets, and similar situations that could make quotes unreliable.

While the Exchange expects that eventually the Floor Procedure Committees will determine to apply the RAES Auto-Step-Up to all or nearly all option classes traded on the floor, the proposed rule change would permit the program to be initiated on a class by class or trading station by station basis.[3] To provide for the orderly introduction of this change to the exchange's RAES procedures and to measure its effect before expanding it to equity options floor-wide, the Exchange intends to introduce the change RAES procedure to selected classes of equity options during an initial evaluation period, and then over time to expand the changed procedure to cover a larger number of equity options unless, upon evaluation, such expansion appears not to be warranted. Members will be given

[1] 15 U.S.C. 78s(b)(1).

[2] In Amendment No. 1, the Exchange clarifies the operation of the proposed rule change. More specifically, the Amendment explains the process of designating options to which the proposed automatic execution feature applies as well as reasons for suspending the new feature. See Letter from Timothy Thompson, Director, Regulatory Affairs, Legal Department, CBOE, to Ken Rosen, Attorney, Division of Market Regulation, Commission, dated May 11, 1998 (''Amendment No. 1'').

[3] See Amendment No. 1.

advance notice of each class of options to which these revised procedures apply.

By enhancing the ability of eligible retail orders in multiply-traded options to receive best execution, the Exchange believes the proposed rule change will promote just and equitable principles of trade and protect investors and the public interest, in furtherance of the objectives of Section 6(b)(5) of the Act.

B. Self-Regulatory Organization's Statement on Burden on Competition

The CBOE does not believe that the proposed rule change will impose any burden on competition.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

No written comments were solicited or received with respect to the proposed rule change.

III. Date of Effectiveness of 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. 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 Commissions, Public Reference Room. Copies of such filing will also be available for inspection and copying at the principal office of the CBOE. All Submissions should refer to File No. SR–CBOE–98–13 and should be submitted by June 11, 1998.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[4]

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 98–13501 Filed 5–20–98; 8:45 am]

BILLING CODE 8010–01–M

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–39991; File No. SR–CHX–98–10]

Self-Regulatory Organizations; Notice of Filing and Immediate Effectiveness of Proposed Rule Change by the Chicago Stock Exchange, Inc., Relating to Membership Dues and Fees

May 13, 1998.

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 April 27, 1998, the Chicago Stock Exchange, Inc. (''CHX'' or ''Exchange''), filed with the Securities and Exchange Commission (''SEC'' or ''Commission'') the proposed rule change as described in Items I, II, and III below, which Items have been prepared by the CHX. The Commission is publishing this notice to solicit comments on the proposed rule change from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to amend its membership dues and fees schedule.

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 Proposed of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

The purpose of the proposed rule change is twofold. First, the proposed rule change would reduce the total fixed fee paid by specialist from $345,000 to $220,000 per month. This reduction reflects a continuing effort by the Exchange to enhance the effectiveness and efficiency of its specialists' operations by reducing costs and thereby encouraging improved competition.

Second, the proposed rule change will expand the type of charges which are eligible to be offset by transaction credits to include the cost of rebills—certain fees and charges that are paid by the Exchange and then ''rebilled'' to the specialists. The Exchange has concluded that the economic rationale for providing transaction credits as an offset to specialist fees is equally applicable to rebills and to other monthly fees owed by specialists, as both charges represent actual expenses to the specialist. Because there is no relevant distinction between rebills and other monthly fees, the application of transaction credits to both types of fees eliminates an artificial barrier and results in the appropriate recognition of the contribution of the specialists to overall CHX revenue. This proposed rule change is particularly important in light of the fact that numerous CHX specialist units have entirely offset their fixed fees and are again in a position where their future contribution to overall CHX revenue will not be recognized.

The Exchange's Finance Committee has determined that after the proposed changes in fee structure, the Exchange will have ample capital and resources to continue to fulfill its proscribed duties in its capacity as a self-regulatory organization and as a registered national securities exchange.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with section 6(b)(4) of the Act[3] in that it provides for the equitable allocation of reasonable dues, fees and other charges among its members.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that he proposed rule change will impose any inappropriate burden on competition.

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[4] 17 CFR 200.30–3(a)(12).

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78f(b)(40.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received from Members, Participants, or Others

No written comments were solicited or received.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change establishes or changes a due, fee, or other charge imposed by the Exchange and, therefore, has become effective pursuant to section 19(b)(3)(A) of the Act[4] and subparagraph (e) of Rule 19b–4 thereunder.[5] At any time within 60 days of the filing of the proposed rule change, the Commission may summarily abrogate such rule change if it appears to the Commission that such action is necessary or appropriate in the public interest, for the protection of investors, or otherwise in furtherance of the purposes of the Act.

IV. Solicitation of Comments

Interested person 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. 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, 450 Fifth Street, NW., Washington, DC 20549. Copies of such filing will also be available for inspection and copying at the principal office of the Exchange. All submissions should refer to File No. SR–CHX–98–10 and should be submitted by June 11, 1998.

For the Commission, by the Division of Market Regulation, pursuant to delegated authority.[6]

[4] 15 U.S.C. 78s(b)(3)(A).

[5] 17 CFR 240.19b–4(e).

[6] 17 CFR 200.30–3(a)(12).

Margaret H. McFarland,

Deputy Secretary.

[FR Doc. 98–13502 Filed 5–20–98; 8:45 am]

BILLING CODE 8010–01–M

DEPARTMENT OF STATE

[Public Notice 2820]

Bureau of Finance and Management Policy

AGENCY: Department of State.

ACTION: 30-Day notice of information collection; client satisfaction survey.

SUMMARY: The Department of State has submitted the following information collection request to the Office of Management and Budget (OMB) for approval in accordance with the Paperwork Reduction Act of 1995. Comments should be submitted to OMB within 30 days of the publication of this notice.

The following summarizes the information collection proposal submitted to OMB:

Type of Request: New Collection.

Originating Office: Bureau of Finance and Management Policy.

Title of Information Collection: Client Satisfaction Survey.

Frequency: Annually.

Form Number: None.

Respondents: Foreign Service annuitants.

Estimated Number of Respondents: 3,000.

Average Hours Per Response: 30 minutes.

Total Estimated Burden: 1,500.

- Evaluate whether the proposed information collection is necessary for the proper performance of the agency functions.
- Evaluate the accuracy of the agency's estimate of the burden of the proposed collection.
- Enhance the quality, utility, and clarity of the information to be collected.
- Minimize the reporting burden on those who are to respond, including through the use of automated collection techniques or other forms of technology.

FOR FURTHER ADDITIONAL INFORMATION: Copies of the proposed information collection and supporting documents may be obtained from Charles S. Cunningham, Directives Management Branch, Department of State, Washington, DC 20520, (202) 647–0596. Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposed survey by name and/or OMB Control Number and should be sent to: OMB, Ms. Victoria Wassmer, (202) 395–5871.

Dated: March 16, 1998.

Glen H. Johnson,

Acting Chief Information Officer.

[FR Doc. 98–13586 Filed 5–20–98; 8:45 am]

BILLING CODE 4710–01–M

DEPARTMENT OF TRANSPORTATION

Office of the Secretary

[Docket No. OST–98–3713]

Enforcement Policy Regarding Unfair Exclusionary Conduct in the Air Transportation Industry

AGENCY: Office of the Secretary, DOT.

ACTION: Notice extending comment period.

SUMMARY: The Department (or DOT) has issued a proposed Statement of the Department of Transportation's Enforcement Policy Regarding Unfair Exclusionary Conduct in the Air Transportation Industry. On April 10, 1998, the Department published the proposed statement and requested public comment. By this notice, the Department is now extending the due date for comments to July 24, 1998 from June 9, 1998 and the due date for reply comments to September 8, 1998 from July 9, 1998.

DATES: Comments must be submitted on or before July 24, 1998. Reply comments must be submitted on or before September 8, 1998.

ADDRESSES: To facilitate the consideration of comments, each commenter should file eight copies of each set of comments. Comments must be filed in Room PL–401, Docket OST–98–3713, U.S. Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590. Late-filed comments will be considered to the extent possible.

FOR FURTHER INFORMATION CONTACT: Jim Craun, Director (202–366–1032) or Randy Bennett, Deputy Director (202–366–1053), Office of Aviation and International Economics, Office of the Assistant Secretary for Aviation and International Affairs, or Betsy Wolf (202–366–9349), Senior Trial Attorney, Office of the Assistant General Counsel for Aviation Enforcement and Proceedings, U.S. Department of Transportation, 400 Seventh St. SW., Washington, DC 20590.

SUPPLEMENTARY INFORMATION: DOT published a proposed Statement of the Department of Transportation's Enforcement Policy Regarding Unfair Exclusionary Conduct in the Air Transportation Industry and requested comments on the proposed statement

(63 FR 17919, April 10, 1998). The proposed policy statement was developed by the Department of Transportation in consultation with the Department of Justice and sets forth tentative findings and guidelines for use by DOT in evaluating whether major air carriers' competitive responses to new entry warrant enforcement action under 49 U.S.C. 41712. The due dates for comments and reply comments were June 9, 1998 and July 9, 1998, respectively.

On May 8, 1998, the Air Transport Association of America (ATA), an association of 22 U.S. airlines and five foreign carriers, filed an emergency petition requesting that the Department extend the time for filing comments by 120 days. The ATA stated that it was filing the petition on an emergency basis because fewer than 30 days remained in the comment period. It claimed that the 60-day time period originally set does not give the parties adequate time to prepare well-reasoned responses to the complicated economic, legal, and policy issues raised in the statement and that in order to participate in a full discussion of these issues, the ATA and its member airlines must consult with economic and legal experts. Since those experts must review studies, reports, and other data that address these issues, the ATA argued that the current 60-day comment period is inadequate.

The ATA also asserted that the Department has failed to identify the research and source material for its proposed statement on a timely basis and therefore an extension of the comment period is necessary. Citing Department rules in 49 CFR § 5.25(a), the ATA likewise stated the Secretary is to grant a petition for extension of time where the petitioner shows that additional time is in the public interest, so long as the petitioner has good cause for the extension and a substantive interest in the proposed action. The ATA claimed that the extension is clearly in the public interest and is consistent with previous similar Department rulemakings involving complex economic issues. Furthermore, as an association representing the entities that the statement would affect, the ATA pointed out that it has an obvious substantive interest.

We have determined that it would be reasonable and in the public interest to give commenters more time for preparing their responses to the proposed statement. While the issues are complex and the statement involves a major policy initiative, we do not agree, however, with the ATA that an extension of 120 days is necessary. The addition of 60 days to the 90 days already established for comments and reply comments provides commenters with a total of 150 days to prepare and provide remarks—an amount of time that we find is sufficient to balance the needs for an adequate comment period while not unnecessarily delaying the Department's initiative for promoting competition and protecting consumers. We will therefore give commenters an additional 60 days to prepare their comments and reply comments.

Specifically, the due date for comments will be extended to July 24, 1998 from June 9, 1998 and the due date for reply comments will be extended to September 8, 1998 from July 9, 1998. (Since the actual addition of 60 days results in a due date for reply comments of September 7, 1998—a Federal holiday, the due date for reply comments was extended to September 8, 1998.)

Issued in Washington, DC, on May 18, 1998, under authority delegated by 49 CFR 1.56(a).

Charles A. Hunnicutt,

Assistant Secretary for Aviation and International Affairs.

[FR Doc. 98–13698 Filed 5–19–98; 10:07 am]

BILLING CODE 4910–62–P

DEPARTMENT OF TRANSPORTATION

Coast Guard

[CGD08–97–050]

Lower Mississippi River Waterway Safety Advisory Committee

AGENCY: Coast Guard, DOT.

ACTION: Notice of meetings.

SUMMARY: The Lower Mississippi River Waterway Safety Advisory Committee (LMRWSAC) will meet to discuss various issues relating to navigational safety on the Lower Mississippi River and related waterways. The meeting will be open to the public.

DATES: LMRWSAC will meet on Monday, June 15, 1998, from 9:00 a.m. to 12 noon. This 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 June 5, 1998. Requests to have a copy of your material distributed to each member of the committee or subcommittee should reach the Coast Guard on or before June 5, 1998.

ADDRESSES: LMRWSAC will meet in the basement conference room of the Hale Boggs Federal Building, 501 Magazine Street, New Orleans, LA. Send written material and requests to make oral presentations to Mr. M.M. Ledet, Commander, Eighth Coast Guard District (m), 501 Magazine Street, New Orleans, LA 70130–3396.

FOR FURTHER INFORMATION CONTACT: M.M. Ledet, committee administrator, telephone 504–589–4686, fax 504–589–4999.

SUPPLEMENTARY INFORMATION: Notice of this meeting is given under the Federal Advisory Committee Act, 5 U.S.C. App. 2.

Agendas of Meeting

Lower Mississippi River Waterways Safety Advisory Committee (MLRWSAC). The agenda includes the following:

(1) Introduction of committee members.
(2) Introduction and remarks by RADM P. Pluta, Committee Sponsor.
(3) Approval of the January 28, 1998 minutes.
(4) Old Business.
  a. Widening of the navigational channel.
  b. VTS update.
  c. Bridge clearance gauges.
(5) New Business.
  a. South Pass dredging.
  b. Bear Industries permit request.
  c. Southwest Pass wingdam.
  d. Visual surveillance of area around new steel dock at Mississippi River mile 161.0.
(6) Next meeting.
(7) Adjournment.

Procedural

The meeting is open to the public. At the Chairs' discretion, members of the public may make oral presentations during the meetings. If you would like to make an oral presentation at a meeting, please notify the Committee Administrator no later than June 5, 1998. Written material for distribution at a meeting should reach the Coast Guard no later than June 5, 1998. If you would like a copy of your material distributed to each member of the committee or subcommittee in advance of a meeting, please submit 28 copies to the Committee Administrator no later than June 5, 1998.

Information on Services for Individuals with Disabilities

For information on facilities or services for individuals with disabilities or to request special assistance at the meetings, contact the Committee Administrator as soon as possible.

Dated: May 5, 1998.

A.L. Gerfin, Jr.,

Capt., USCG, Acting Commander, Eighth Coast Guard District.

[FR Doc. 98–13640 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–15–M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Draft Advisory Circular (AC) No. 120–28D, Criteria for Approval of Category III Weather Minima for Takeoff, Landing, and Rollout

AGENCY: Federal Aviation Administration, DOT.

ACTION: Notice of availability of a draft advisory circular.

SUMMARY: This notice announces the availability of a draft AC, recommended by the Aviation Rulemaking Advisory Committee (ARCA), which provides information and guidance on obtaining and maintaining approval of Category III landing weather minima and low visibility takeoff criteria, including the installation and approval of associated aircraft systems. This draft AC would incorporate changes to AC 20–57 resulting from the harmonization efforts of the Federal Aviation Administration, European Joint Aviation Authority and other regulatory authorities. This notice solicits public comment on the draft AC.

DATES: Comments on the draft AC must be received on or before July 20, 1998.

ADDRESSES: Send all comments on the draft AC to Jim Enias, Technical Programs Division (AFS–400), Room 835, Federal Aviation Administration, 800 Independence Ave., SW., Washington DC 20591.

FOR FURTHER INFORMATION CONTACT: Jim Enias, Technical Programs Division (AFS–400), Federal Aviation Administration, Independence Avenue, SW., Washington, DC 20591, Telephone (202) 267–7211.

Comments Invited

The FAA invites interested parties to submit comments on this draft AC, as recommended by the ARAC. Commenters should identify AC 120–28D and submit comments to the person and address listed above. The FAA will consider all communications received on or before the closing date for comments before completing its review of this ARAC recommended AC. The recommended draft AC and comments received may be inspected at the Office of Flight Standards Service, Technical Programs Division, Room 935, Federal Aviation Administration (Federal Office Building 10A), between the hours of 9 a.m. and 5 p.m. weekdays, except Federal holidays.

Background

This draft AC was received from the ARAC on December 15, 1997. The AC recommended by the ARAC would set forth an acceptable means, but not the only means, of obtaining and maintaining approval of operations in Category III landing weather minima and low visibility takeoff criteria including the installation and approval of associated aircraft systems. It includes additional or revised Category III criteria for use in conjunction with heads-up displays, satellite navigation systems, low visibility takeoff guidance systems, wide-body fail passive operations, and use of Category III criteria during certain engine inoperative operations.

This draft AC should be reviewed in conjunction with the regulatory requirements of 14 CFR parts 121, 125, and 135, as applicable. This draft AC would not change, add, or delete any regulatory requirement or authorize any deviation from parts 121, 125, or 135.

This draft revision also updates and incorporates provisions of the former AC 20–57 into AC 120–28, since AC 20–57's former provisions are directly related to and dependent on criteria provided in the draft AC.

The FAA is currently reviewing this ARAC recommendation and may make revisions to this document before it is issued. These revisions may include editorial changes to ensure that this AC does not impose requirements on operators independent of the current regulations. The regulations themselves, referenced in the draft AC, may be reviewed for revisions, as appropriate. It should be noted that the draft AC explicitly states that nothing in it is intended to preclude an operator from proposing and demonstrating to the FAA its ability to operate to Category III minima with a different equipment configuration, or alternatively to an RVR minima lower than presently described in this document.

If, after review of this recommendation, the FAA decides to make any substantive changes in the draft AC, the revised document will be made available again for comment before final issuance.

This draft revision incorporates changes resulting from the first steps toward international all weather operations criteria harmonization taken by the FAA, JAA, and several other regulatory authorities. Subsequent revisions of this AC are planned as additional all weather operations harmonization items are agreed and completed by FAA and JAA, or internationally.

Issued in Washington, DC on May 15, 1998.

Thomas E. Stuckey,

Acting Director, Flight Standards Service.

[FR Doc. 98–13578 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Aviation Rulemaking Advisory Committee Meeting on Transport Airplane and Engine Issues

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of public meeting.

SUMMARY: This notice announces a public meeting of the FAA's Aviation Rulemaking Advisory Committee (ARAC) to discuss transport airplane and engine (TAE) issues.

DATES: The meeting is scheduled for June 8 and 9, 1998, beginning at 8:30 a.m. on June 8. Arrange for oral presentations by June 1, 1998.

ADDRESSES: Aerospace Industries Association, 1250 Eye Street, NW. (Suite 1100), Washington, DC.

FOR FURTHER INFORMATION CONTACT: Effie M. Upshaw, Office of Rulemaking, ARM–209, FAA, 800 Independence Avenue, SW., Washington, DC 20591, Telephone (202) 267–7626.

SUPPLEMENTARY INFORMATION: Pursuant to section 10(a)(2) of the Federal Advisory Committee Act (Pub.L. 92–463; 5 U.S.C. App II), notice is given of an ARAC meeting to be held June 8–9, 1998, at Aerospace Industries Association, 1250 Eye Street, NW. (Suite 1100), Washington, DC. The agenda will include:

Monday, June 8, 1998

- Opening Remarks.
- FAA Report.
- Joint Aviation Authorities (JAA) Report.
- Transport Canada Report.
- Executive Committee (EXCOM) Meeting Report.
- Harmonization Management Team Report.
- Harmonization Program Plan.
- Flight Test Harmonization Working Group (HWG) Report.
- Systems Design and Analysis HWG Report and Vote.
- Ice Protection HWG Report.
- Powerplant Installation HWG Report.
- Engine HWG Report.
- Flight Guidance System HWG Report.

Tuesday, June 9, 1998

- General Structures HWG Report.
- Electromagnetic Effects HWG Report.
- Loads & Dynamics HWG Report.
- Airworthiness Assurance HWG Report.
- Hydraulic Test HWG Report and Vote.
- Brake Systems Harmonization Working Group (if needed).
- Review Action Items.

The Systems Design and Analysis HWG is requesting a vote for formal FAA economic and legal review of a draft notice and advisory circular relating to a review of 14 CFR 25.1309, European Joint Aviation Requirements (JAR) 25.1309, associated Advisory Circular 25.1309–1A, and Advisory Circulars Joint Numbers 1 through 8. The Hydraulic Test HWG is requesting a vote for the acceptance of a disposition of comments to Notice of Proposed Rulemaking No. 96–6. The proposed rulemaking would amend the airworthiness standards for transport category airplanes to harmonize hydraulic systems design and test requirements with standards proposed for the JAR.

Attendance is open to the public, but will be limited to the space available. Arrangements may be made to present statements, request the public must make arrangements by June 1, 1998, to present oral statements at the meeting. Written statements may be presented to the Committee at any time by providing 25 copies to the Assistant Executive Director for Transport Airplane and Engine issues or by providing copies at the meeting. Copies of the documents to be voted upon may be made available by contacting the person listed under the heading **FOR FURTHER INFORMATION CONTACT**.

Sign and oral interpretation can be made available at the meeting, as well as an assistive listening device, if requested 10 calendar days before the meeting.

Issued in Washington, DC on May 13, 1998.

Joseph A. Hawkins,

Executive Director, Aviation Rulemaking Advisory Committee.

[FR Doc. 98–13519 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Intent To Rule on PFC Application (98–03–I–00–OTH) To Impose Only a Passenger Facility Charge (PFC) at North Bend Municipal Airport; Submitted by the City of North Bend, North Bend, Oregon

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 only a PFC at North Bend Municipal Airport under the provisions of 49 U.S.C. 40117 and part 158 of the Federal Aviation Regulations (14 CFR Part 158).

DATES: Comments must be received on or before June 22, 1998.

ADDRESSES: Comments on this application may be mailed or delivered in triplicate to the FAA at the following address: J. Wade Bryant, Manager; Seattle airports District Office, SEA–ADO; Federal Aviation Administration; 1601 Lind Avenue, S.W., Suite 250; Renton, Washington 98055–4056.

Om addition, one copy of any comments submitted to the FAA must be mailed or delivered to Gary Le Tellier, Airport Manager, at the following address: City of North Bend, P.O. Box B, North Bend, OR 97459.

Air carriers and foreign air carriers may submit copies of written comments previously provided to North Bend Municipal airport under section 158.23 of Part 158.

FOR FURTHER INFORMATION CONTACT: Ms. Mary Vargas, (425) 227–2660; Seattle Airports District Office, SEA–ADO; Federal Aviation Administration; 1601 Lind Avenue, S.W., Suite 250; Renton, Washington 98055–4056. 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 (98–03–I–00–OTH) to impose only a PFC at North Bend Municipal Airport, under the provisions of 49 U.S.C. 40117 and Part 158 of the Federal Aviation Regulations (14 CFR Part 158).

On May 13, 1998, the FAA determined that the application to impose only a PFC submitted by the City of North Bend, Oregon, was substantially complete within the requirements of section 158.25 of Part 158. The FAA will approve or disapprove the application, in whole or in part, no later than August 22, 1998.

The following is a brief overview of the application.

Level of the proposed PFC: $3.00.

Proposed charge effective date: June 1, 1998.

Proposed charge expiration date: January 1, 2001.

Total estimated PFC revenue: $136,800.

Brief description of proposed projects—(Impose Only): East Side.

Terminal Area Site Preparation; and East Airport Roadway Alignment, and Runway 13—31 Safety Area.

Class or classes of air carriers which the public agency has requested not be required to collect PFCs: Non-scheduled air taxi/commercial operators utilizing aircraft having a seating capacity of less than 20 passengers not to be required to collect PFCs.

Any person may inspect the application in person at the FAA office listed above under **FOR FURTHER INFORMATION CONTACT** and at the FAA Regional Airports Office located at: Federal Aviation Administration, Northwest Mountain Regional Office, Airports Division, 1601 Lind Avenue, S.W., Suite 315; Renton, Washington 98055–4056.

In addition, any person may, upon request, inspect the application, notice, and other documents germane to the application in person at the North Bend Municipal Airport, North Bend, Oregon.

Issued in Renton, Washington on May 134, 1998.

David A. Field,

Manager, Planning, Programming and Capacity Branch, Northwest Mountain Region.

[FR Doc. 98–13576 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–13–M

DEPARTMENT OF TRANSPORTATION

National Highway Traffic Safety Administration

[Docket No. NHTSA–98–3701; Notice 1]

Mitsubishi Motor Sales of America Inc.; Receipt of Application for Decision of Inconsequential Noncompliance

Mitsubishi Motor Sales of America (MMSA) of Cypress, California, has determined that some of its 1994–1998 models fail to meet the requirements of Federal Motor Vehicle Safety Standard (FMVSS) No. 118, ''S4,'' and has filed an appropriate report pursuant to 49 CFR Part 573, ''Defects and Noncompliance Reports.'' MMSA has also applied to be exempted from the notification and remedy requirements of 49 U.S.C. Chapter 301—''Motor Vehicle Safety'' on the basis that the

noncompliance is inconsequential to motor vehicle safety.

This notice of receipt of an application is published under 49 U.S.C. 30118 and 30120 and does not represent any agency decision or other exercise of judgment concerning the merits of the application.

During the periods indicated below, the applicant imported and sold and/or distributed approximately 57,294 vehicles equipped with power sunroofs that did not meet certain requirements mandated by Federal Motor Vehicle Safety Standard (FMVSS) No. 118. Specifically, FMVSS No. 118 requires that power windows, partitions, and sunroofs only be operable under certain circumstances. One of those circumstances specifies that a power sunroof may operate:

during the interval between the time the locking device which controls the activation of the vehicle's engine is turned off and the opening of either of a two-door vehicle's doors or, in the case of a vehicle with more than two doors, the opening of either of its front doors. 49 CFR 571.118 S4(e) states that once the ignition key is turned off and either of the two front doors is opened, the power sunroof must not operate.

In the Mitsubishi vehicles identified below, activation of the power sunroof stops immediately after the ignition is turned off and the driver's side door is open. The sunroof continues to operate, however, for thirty seconds after the ignition is turned off and the passenger front door is opened. This continued operation does not comply with the requirements of S4 FMVSS No.118.

Make	Line	Model year	No. of affected vehicles	Dates of manufacture
MMC	Mitsubishi 3000GT	1994–98	5,855	5/94—4/98
MMC	Mitsubishi Mirage (Coupe & Sedan)	1997–98	1,383	6/96—5/98
Mitsubishi Motor Manufacturing of America, Inc.	Mitsubishi Galant	1994–98	50,056	3/93—3/98

MMSA supports its application for inconsequential noncompliance with the following:

MMSA does not believe that the foregoing noncompliance will impact motor vehicle safety for the following reasons, FMVSS 118 sets forth requirements for power operated windows, partitions, and roof panel systems (e.g., sunroofs) to minimize the risk of injury or death from accidental operation of these systems. The National Highway Traffic Safety Administration (NHTSA or the Agency) has identified children as the group of people most likely at risk from unsupervised or inadvertent operation of power windows and sunroofs. See 57 FR 23958 (1992). In order to address the foregoing concerns, FMVSS 118 S4 specifies the conditions under which a power window, partition or sunroof may operate. S4(e) specifically requires that power windows, partitions and sunroofs not be operational when the ignition key is off *and* either one of the vehicle's front doors is opened. The power windows may continue to operate after the ignition has been turned off, but prior to the opening of either of the vehicle's front doors.

''FMVSS 118 S4(e) was designed to reduce the possibility of *unsupervised* children from operating the power windows, partitions or sunroofs in a vehicle. Specifically, S4(e) is based on the logical presumption that after a vehicle's ignitions is turned off, but prior to opening either of the vehicle's front doors, an adult will remain in the vehicle to supervise and protect children from the safety risks associated with operation of a power window, partition, or sunroof system. Hence there is little to no additional risk in allowing continued operation of the power window, partition or sunroof after the ignition is turned off but prior to the opening of either front door because of the presence of the supervising adult. This premise is especially true for the driver side door. In most circumstances, and adult driver normally exits the vehicle from the driver side door. If the vehicle's driver side door has not been opened, the adult driver is most likely still in the vehicle''.

MMSA believes that the failure to comply is inconsequential to motor vehicle safety for the following reasons:

''The power sunroof immediately ceases to operate when the ignition key is turned off and the driver side door is open. The sunroof will continue to operate, however, for approximately 30 seconds after the ignition key is turned off and the passenger side door is open. The rationale supporting this feature was to allow the driver to close the sunroof even if the driver has turned off the ignition and the passenger has opened the door and exited the vehicle. This delay in operation cut-off is a convenience feature similar to those found in Japanese and European versions of the affected Mitsubishi vehicles. As long as the driver door remains closed, the adult driver inevitably remains in the vehicle to supervise any operation of the power sunroof. It is highly unlikely that the driver would exit from the front passenger side in the affected vehicles. Each of the vehicles listed above has a front seating configuration consisting of two bucket type seats and a center console that rises up from the floor space between the driver and passenger seats. The transmission shift lever for these automatic and standard transmission vehicles rises up from the center console. The combination of bucket seats, center console, and gear shift make exiting the affected vehicles from the driver's side through the passenger side door extremely difficult and highly unfeasible. In addition, the period of operation for the sunroof after the front passenger door is extremely short (i.e., 30 seconds). This short period of time is sufficient to allow drivers to close the sunroof prior to exiting the vehicle, but insufficient to cause any safety concerns for children. Consequently, continued, short-term operation of the sunroof after the ignition has been turned off and the passenger side door opened, but prior to the opening of the driver's side door, does not pose any significant safety concern. The probability of unsupervised children being exposed to injury from the foregoing sunroof system during the 30 seconds after the ignition key has been turned off and the front passenger door only is opened is non-existent.''

Additionally, MMSA asserts that the situation is similar to another situation involving vehicles manufactured by Volkswagen of America, Inc. (Volkswagen). In Volkswagen's case, the company manufactured approximately 20,000 vehicles with power windows. The power windows ceased to operate immediately after the ignition was turned off and the driver's size door was opened. The windows continued to operate, however, for ten minutes after the ignition was turned off and the front passenger door only was opened. Volkswagen petitioned the Agency for a determination of inconsequential noncompliance. See 60 FR 26475 (1995). NHTSA granted the petition based on reasons similar to those set forth above by MMSA. See 60 FR 48197 (1995).

Interested persons are invited to submit written data, views, and arguments on the application of the petitioner described above. Comments should refer to the docket number and be submitted to: Docket Section, National Highway Traffic Safety Administration, Room 5109, 400 Seventh Street, SW., Washington, DC 20590. It is requested but not required that six copies be submitted.

All comments received before the close of business on the closing date indicated below will be considered. The application and supporting materials, and all comments received after the closing date, will also be filed and will be considered to the extent possible. When the application is granted or denied, the notice will be published in

the **Federal Register** pursuant to the authority indicated below.

Comment closing date: June 28, 1998.

(49 U.S.C. 30118 and 30120; delegations of authority at 49 CFR 1.50 and 501.8)

Issued on: May 14, 1998.

L. Robert Shelton,

Associate Administrator for Safety Performance Standards.

[FR Doc. 98–13520 Filed 5–20–98; 8:45 am]

BILLING CODE 4910–59–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Finance Docket No. 33567]

Albany & Eastern Railroad Company—Acquisition and Operation Exemption—The Burlington Northern and Santa Fe Railway Company

Albany & Eastern Railroad Company (AERC), a noncarrier, has filed a verified notice of exemption under 49 CFR 1150.31 to acquire from The Burlington Northern and Santa Fe Railway Company (BNSF), and to operate 17.40 miles of rail line between MP–14.50, at or near Lebanon, and MP–31.90, at or near Foster, in Linn County, OR.[1] AERC also is acquiring incidental trackage rights over Union Pacific Railroad Company's (UP) rail line between MP–688.96, at or near Lebanon, and MP–691.52, at or near Albany, and over BNSF's line between MP–0.0, at Albany, and MP–0.89, east of Albany, in Linn County, OR, a total of 13.62 miles. The incidental trackage rights will permit AERC to interchange traffic with BNSF at its Albany yard.

The transaction was expected to be consummated on or shortly after May 8, 1998.

If the verified notice contains false or misleading information, the exemption is void *ab initio.* Petitions to revoke the exemption under 49 U.S.C. 10502(d) may be filed at any time. The filing of a petition to revoke will not automatically stay the transaction.

An original and 10 copies of all pleadings, referring to STB Finance Docket No. 33567, must be filed with the Surface Transportation Board, Office of the Secretary, Case Control Unit, 1925 K Street, N.W., Washington, DC 20423–0001. In addition, one copy of each pleading must be served on Fritz R. Kahn, Suite 750 West, 1100 New York Avenue, N.W., Washington, DC 20005–3934.

[1] AERC will acquire the track, ties, and other improvements, and a permanent, irrevocable easement to operate on this line, but not the real estate.

Board decisions and notices are available on our website at ''WWW.STB.DOT.GOV.''

Decided: May 14, 1998.

By the Board, David M. Konschnik, Director, Office of Proceedings.

Vernon A. Williams,

Secretary.

[FR Doc. 98–13593 Filed 5–20–98; 8:45 am]

BILLING CODE 4915–00–P

DEPARTMENT OF TRANSPORTATION

Surface Transportation Board

[STB Docket No. AB–494X]

Akron Barberton Cluster Railway Company—Abandonment Exemption—in Summit County, OH

Akron Barberton Cluster Railway Company (ABCR) has filed a notice of exemption under 49 CFR 1152 Subpart F—*Exempt Abandonments* to abandon 4.14 miles of its line of railroad from Valuation Station 440 + 00 at Main Street to Valuation Station 658 + 63 at Seiberling Avenue, in Summit County, OH. The line traverses United States Postal Service Zip Codes 44301, 44305, 44300 and 44311.

ABCR has certified that: (1) no local traffic has moved over the line for at least 2 years; (2) any overhead traffic on the line can be rerouted over other lines; (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 June 20, 1998, 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 June 1, 1998. Petitions to reopen or requests for public use conditions under 49 CFR 1152.28 must be filed by June 10, 1998, with: Surface Transportation Board, Office of the Secretary, Case Control Unit, 1925 K Street, NW, Washington, DC 20423. A copy of any petition filed with the Board should be sent to applicant's representative: Christopher E. V. Quinn, Oppenheimer Wolff & Donnelly, Two Prudential Plaza, 45 Floor, 180 North Stetson Avenue, Chicago, IL 60601.

If the verified notice contains false or misleading information, the exemption is void *ab initio.*

ABCR has filed an environmental report which addresses the abandonment's effects, if any, on the environment and historic resources. The Section of Environmental Analysis (SEA) will issue an environmental assessment (EA) by May 26, 1998. Interested persons may obtain a copy of the EA by writing to SEA (Room 500, Surface Transportation Board, Washington, DC 20423) or by calling SEA, at (202) 565–1545. Comments on environmental and historic preservation matters must be filed within 15 days 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), ABCR 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 ABCR's filing of a notice of consummation by May 21, 1999, 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: May 8, 1998.

[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 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 offer of financial assistance must be accompanied by the filing fee, which currently is set at $1000. *See* 49 CFR 1002.2(f)(25).

By the Board, David M. Konschnik, Director, Office of Proceedings.

Vernon A. Williams

Secretary.

[FR Doc. 98–13093 Filed 5–20–98; 8:45 am]

BILLING CODE 4915–00–P

UNITED STATES INFORMATION AGENCY

College and University Partnerships Program for Russian Regional Investment Initiative in Samara Oblast

ACTION: Request for proposals.

SUMMARY: The Office of Academic Programs of the United States Information Agency's Bureau of Educational and Cultural Affairs announces an open competition for an assistance award program. Accredited, post-secondary educational institutions meeting the provisions described in IRS regulation 26 CFR 1.501(c) may apply to develop a partnership with a specified institution of higher education from Russia in specified fields. Non-profit organizations meeting the provisions described in IRS regulation 26 CFR 1.501(c) may also apply to facilitate a partnership between a U.S. college or university with one of the foreign institutions.

USIA seeks proposals from US universities, or NGOs representing US universities, to develop partnerships with one of the two following Russian institutions of higher learning: with the Samara State Aerospace University's International Marketing Institute in the field of public administration; or with the Togliatti Academy of Business and Banking in the field of business education.

Participating institutions exchange faculty and administrators for a combination of teaching, lecturing, faculty and curriculum development, collaborative research, and/or outreach, for periods ranging from one week (for planning visits) to an academic year. The FY 98 program will also support the establishment and maintenance of Internet and/or e-mail communication facilities as well as interactive distance learning programs at foreign partner institutions. Applicants may propose other project activities not listed above that are consistent with the goals and activities of the College and University Partnerships Program.

The program awards up to $150,000 for a two-year period to defray the cost of travel and per diem with an allowance for educational materials and some aspects of project administration. Grants awarded to organizations with less than four years of experience in conducting international exchange programs will be limited to $60,000. USIA anticipates awarding two grants in the amount of $150,000 each.

Overall grant-making authority for this program is contained in the Mutual Educational and Cultural Exchange Act of 1961, Pub. L. 87–256, as amended, also known as the Fulbright-Hays Act. The purpose of the Act is ''to enable the Government of the United States to increase mutual understanding between the people of the United States and the people of other countries * * *; to strengthen the ties which unite us with other nations by demonstrating the educational and cultural interests, developments, and achievements of the people of the United States and other nations * * * and thus to assist in the development of friendly, sympathetic and peaceful relations between the United States and the other countries of the world.'' The funding authority for the program cited above is provided through the Freedom for Russia and Emerging Eurasian Democracies and Open markets Support Act of 1992 (Freedom Support Act). Programs and projects must conform with Agency requirements and guidelines outlined in the Solicitation Package. USIA projects and programs are subject to the availability of funds.

Announcement Title and Number: All communications with USIA concerning this RFP should refer to the College and University Partnerships Program for Russian Regional Investment Initiative in Samara Oblast and reference number E/ASU–98–09.

Deadline For Proposals: All copies must be received at the U.S. Information Agency by 5 p.m. Washington, DC time on Friday, July 17, 1998. Faxed documents will not be accepted at any time. Documents postmarked by the due date but received at a later date will not be accepted.

Approximate program dates: Grants should begin on or about September 1, 1998.

Duration: September 1, 1998–August 30, 2000.

FOR FURTHER INFORMATION, CONTACT: Office of Academic Programs; Advising, Teaching, and Specialized Programs Division; Specialized Programs Branch, (E/ASU) room 349, U.S. Information Agency, 301 4th Street, SW., Washington, DC 20547, telephone: (202) 619–4126, fax: (202) 401–1433, internet: jcebra@usia.gov to request a Solicitation Package containing more detailed award criteria; all application forms; and guidelines for preparing proposals, including specific criteria for preparation of the proposal budget.

To Download A Solicitation Package Via Internet: The entire Solicitation Package may be downloaded from USIA's website at http://www.usia.gov/education/rfps. Please read all information before downloading.

To Receive A Solicitation Package Via Fax on Demand: The entire Solicitation Package may be received via the Bureau's ''Grants Information Fax on Demand System'', which is accessed by calling 202/401–7616. Please request a ''Catalog'' of available documents and order numbers when first entering the system.

Please specify USIA Program Officer Jonathan Cebra on all inquiries and correspondence. Interested applicants should read the complete **Federal Register** announcement before sending inquiries or submitting proposals. Once the RFP deadline has passed, Agency staff may not discuss this competition in any way with applicants until the Bureau proposal review process has been completed.

Submissions: Applicants must follow all instructions given in the Solicitation Package. The original and 10 copies of the application should be sent to: U.S. Information Agency, Ref.: E/ASU–98–09, Office of Grants Management, E/XE, Room 326, 301 4th Street, SW., Washington, DC 20547.

Applicants must also submit the ''Executive Summary'' and ''Proposal Narrative'' sections of the proposal on a 3.5″ diskette, formatted for DOS. This material must be provided in ASCII text (DOS) format with a maximum line length of 65 characters. USIA will transmit these files electronically to USIA Moscow for its review, with the goal of reducing the time it takes to get post's comments for the Agency's grants review process.

Diversity, Freedom and Democracy Guidelines

Pursuant to the Bureau's authorizing legislation, programs must maintain a non-political character and should be balanced and representative of the diversity of American political, social, and cultural life. ''Diversity'' should be interpreted in the broadest sense and encompass differences including, but not limited to ethnicity, race, gender, religion, geographic location, socio-economic status, and physical challenges. Applicants are strongly encouraged to adhere to the advancement of this principle both in program administration and in program content. Please refer to the review criteria under the 'Support for Diversity' section for specific suggestions on incorporating diversity into the total proposal. Pub. L. 104–319 provides that

''in carrying out programs of educational and cultural exchange in countries whose people do not fully enjoy freedom and democracy'', USIA ''shall take appropriate steps to provide opportunities for participation in such programs to human rights and democracy leaders of such countries.'' Proposals should account for advancement of this goal in their program contents, to the full extent deemed feasible.

SUPPLEMENTARY INFORMATION:

Guidelines

The College and University Partnership Program for Russian Regional Investment Initiative in Samara Oblast is limited to the following specific academic disciplines:

(1) Public administration—the Russian partner for this partnership must be Samara State Aerospace University's International Marketing Institute and the focus should be on developing training programs for civil servants;

(2) Business education—the Russian partner for this partnership must be the Togliatti Academy of Business and Banking.

Proposals must focus on curriculum, faculty, and staff development in one of these eligible disciplines. Administrative reform at the Russian partner should also be a project component.

Projects should involve the development of new academic programs or the building and/or restructuring of an existing program or programs, and should promote higher education's role in the transition to market economies and open democratic systems. Feasibility studies to plan partnerships will not be considered.

Whenever feasible, participants should make their training and personnel resources, as well as results of their collaborative research, available to government, NGOs, and business.

Participating institutions should exchange faculty and/or staff members for teaching/lecturing and consulting.

U.S. institutions are responsible for the submission of proposals and should collaborate with their foreign partners in planning and preparing proposals. U.S. and foreign partner institutions are encouraged to consult about the proposed project with USIA E/ASU staff in Washington, DC. Preference will be given to proposals which demonstrate evidence of previous relations with the foreign partner institution(s).

Guidelines

U.S. Partner and Participant Eligibility

In the U.S., participation in the program is open to accredited two- and four-year colleges and universities, including graduate schools. Applications from consortia of U.S. colleges and universities are eligible. Applications from non-profit service and professional organizations or non-governmental organizations proposing to facilitate a partnership between a U.S. university and a foreign partner are also eligible. The lead U.S. institution in the consortium is responsible for submitting the application and each application from a consortium must document the lead school's stated authority to represent the consortium. Participants representing the U.S. institution who are traveling under USIA grant funds must be faculty, staff, or advanced graduate students from the participating institution(s) and must be citizens.

Foreign Partner and Participant Eligibility

Overseas, participation is limited to the following institutions:

Samara State Aerospace University's International Marketing Institute—in the field of public administration; Togliatti Academy of Business and Banking—in the field of business education.

Participants represenitng the foreign institutions must be faculty, staff or advanced students of the partner institution, and be citizens, nationals, or permanent residents of the country of the foreign partner, and be qualified to hold a valid passport and U.S. J–1 visa.

Ineligibility

A proposal will be deemed technically ineligible if:

(1) It does not fully adhere to the guidelines established herein and in the Solicitation Package;

(2) It is not received by the deadline;

(3) It is not submitted by the U.S. partner;

(4) One of the partner institutions is ineligible;

(5) The academic discipline(s) is/are not listed as eligible in the RFP, herein;

(6) The amount requested of USIA exceeds $150,000 for the two-year project.

Please refer to program-specific guidelines (POGI) in the Solicitation Package for further details.

Notice

The terms and conditions published in this RFP are binding and may not be modified by any USIA representative. Explanatory information provided by the Agency that contradicts published language will not be binding. Issuance of the RFP does not constitute an award commitment on the part of the Government. The Agency reserves the right to reduce, revise, or increase proposal budgets in accordance with the needs of the program and the availability of funds. Awards made will be subject to periodic reporting and evaluation requirements.

Notification

Final awards cannot be made until funds have been appropriated by Congress, allocated and committed through internal USIA procedures.

Dated: May 14, 1998.

Robert L. Earle,

Deputy Associate Director for Educational and Cultural Affairs.

[FR Doc. 98–13522 Filed 5–20–98; 8:45 am]

BILLING CODE 8230–01–M

DEPARTMENT OF VETERANS AFFAIRS

Advisory Committee on Women Veterans, Notice of Meeting

The Department of Veterans Affairs gives notice under Public Law 92–463 that a meeting of the Advisory Committee on Women Veterans will be held on June 16–19, 1998, at the Department of Veterans Affairs, 810 Vermont Avenue, NW, Washington, DC. The purpose of the Committee is to advise the Secretary of Veterans Affairs regarding the needs of women veterans with respect to health care, rehabilitation, compensation, outreach and other programs, and activities administered by the Department of Veterans Affairs designed to meet such needs. The Committee will make recommendations to the Secretary regarding such activities.

On June 16, 17 and 18, the sessions will convene from 9:00 a.m. to 5:00 p.m. and on June 19, from 9:00 a.m. to 1:00 p.m. The Committee will meet in conference room 230, at VA Central Office. All sessions will be open to the public. It will be necessary for those wishing to attend to contact Ms. Maryanne Carson, Department of Veterans Affairs, Washington, DC (phone 202–273–6193) prior to June 5, 1998. A tentative agenda follows:

Tuesday, June 16, 1998

9:00 am Introduction of new members—Chair/Vice Chair

9:15 am Opening remarks: Secretary Togo D. West, Jr.

10:00 am Briefing: Under Secretary for Benefits

10:30 am Break

10:45 am Briefing: Director, Readjustment Service
11:15 am Briefing: Acting Director, National Cemetery System
11:45 am Briefing: Veterans Service Organizations Liaison
12:15 pm Lunch
1:30 pm Briefing: Under Secretary for Health
2:00 pm Briefing: Center for Veterans Analysis & Statistics
2:30 pm Briefing: DAS for Congressional Affairs
3:00 pm Break
3:15 pm Briefing: Chief, Network Officer
3:45 pm Briefing: DAS Public Affairs
4:15 pm Advisory Committee on Women Veterans, Chair/Vice Chair

Wednesday, June 17, 1998

8:00 am Advisory Committee on Women Veterans, Chair/Vice Chair
8:30 am Report: Women Veterans Health Status, Dr. Katherine Skinner
9:30 am Briefing: Assistant Secretary Veteran's Employment & Training, DOL
10:00 am Briefing: Regional Administrator, Women's Bureau, DOL
10:15 am Break
11:00 am Update: Women Veteran Health Program
11:30 am Update: Persian Gulf Illness & Research Initiatives on Women
12 noon Lunch
1:00 pm Report: Barriers to Care, Dr. Jessica Wolfe
1:30 pm Update: Veterans Benefits Initiatives
2:00 pm Site Visit: Women's Memorial

Thursday, June 18, 1998

8:30 am
Breakout: Subcommittee Working Groups
Legislative—conference room 732
Health Care—conference room 742
1:00 pm
Executive Session
Reports: Subcommittee Working Groups
Discussion: 1998 Report of Advisory Committee
Discussion: Network Strategic Plan Summary 1998–2002

Friday, June 19, 1998

9:00 am
Executive Session
Discussion: Survey of Veterans Report
Discussion: Site Visit fall 1998
Side Visits Reports
Wrap Up
1:00 pm Adjourn

Dated: May 14, 1998.
By Direction of the Secretary.

Heyward Bannister,

Committee Management Officer.

[FR Doc. 98–13527 Filed 5–20–98; 8:45 am]

BILLING CODE 8320–01–M

federal register

Thursday
May 21, 1998

Part II

Environmental Protection Agency

40 CFR Parts 72 and 75

Acid Rain Program; Continuous Emission Monitoring Rule Revisions; Acid Rain Program: Determinations Under EPA Study of Bias Test and Relative Accuracy and Availability Analysis; Proposed Rules

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 72 and 75

[FRL–6007–8]

RIN 2060–AG46

Acid Rain Program; Continuous Emission Monitoring Rule Revisions

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Title IV of the Clean Air Act (CAA or the Act), as amended by the Clean Air Act Amendments of 1990, authorizes the Environmental Protection Agency (EPA or Agency) to establish the Acid Rain Program. The Acid Rain Program and the provisions in this proposed rule benefit the environment by preventing the serious, adverse effects of acidic deposition on natural resources, ecosystems, materials, visibility, and public health. The program does this by setting emissions limitations to reduce the acidic deposition precursor emissions of sulfur dioxide and nitrogen oxides. On January 11, 1993, the Agency promulgated final rules, including the final continuous emission monitoring (CEM) rule, under title IV. On May 17, 1995, the Agency published direct final and interim rules to make the implementation of the CEM rule simpler. Subsequently, on November 20, 1996, the Agency published a final rule in response to public comments received on the direct final and interim rules.

These proposed revisions to the CEM rule would make a number of further minor changes to make the implementation of the CEM rule simpler, more streamlined, and more efficient for both EPA and the facilities affected by the rule. Furthermore, the proposed revisions would provide reduced monitoring burdens for affected facility units with low mass emissions. In addition, the proposed revisions would establish quality assurance requirements for moisture monitoring systems and add a new flow monitor quality assurance test to assure the accuracy of data reported from these types of monitoring systems. Finally, the proposed revisions would create a new monitoring option, the F-factor/fuel flow method, for certain units.

DATES: *Comments.* All public comments must be received on or before July 20, 1998.

Public Hearing. Anyone requesting a public hearing must contact EPA no later than May 31, 1998. If a hearing is held, it will take place June 8, 1998, beginning at 10:00 a.m.

ADDRESSES: *Comments.* Comments must be mailed (in duplicate if possible) to: EPA Air Docket (6102), Attention: Docket No. A–97–35, Room M–1500, Waterside Mall, 401 M Street, SW, Washington, DC 20460.

Public Hearing. If a public hearing is requested, it will be held at the Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460, in the Education Center Auditorium. Refer to the Acid Rain homepage at www.epa.gov/acidrain for more information or to determine if a public hearing has been requested and will be held.

Docket. Docket No. A–97–35, containing supporting information used to develop the proposal is available for public inspection and copying from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section at the above address.

FOR FURTHER INFORMATION CONTACT: Jennifer Macedonia, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M Street, SW, Washington, DC 20460, telephone number (202) 564–9123 or the Acid Rain Hotline at (202) 564–9620. Electronic copies of this notice and technical support documents can be accessed through the Acid Rain Division website at http://www.epa.gov/acidrain.

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I. Regulated Entities

Entities potentially regulated by this action are fossil fuel-fired boilers and turbines that serve generators producing electricity, generate steam, or cogenerate electricity and steam. While part 75 primarily regulates the electric utility industry, today's proposal could potentially affect other industries. The proposal includes NO_X mass provisions for the purpose of serving as a model which could be adopted by a state, tribal, or federal NO_X mass reduction program covering the electric utility and other industries. Regulated categories and entities include:

Category	Examples of regulated entities
Industry	Electric service providers, boilers and turbines from a wide range of industries.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This table lists the types of entities which EPA is now aware could potentially be regulated by this action. Other types of entities not listed in the table could also be regulated. To determine whether your facility, company, business, organization, etc., is regulated by this action, you should carefully examine the applicability criteria in §§ 72.6, 72.7, and 72.8 of title 40 of the Code of Federal Regulations. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

II. Background and Summary of the Proposed Rule

Title IV of the Act requires EPA to establish an Acid Rain Program to reduce the adverse effects of acidic deposition. On January 11, 1993, the Agency promulgated final rules implementing the program, including the CEM rule (58 FR 3590–3766). Technical corrections were published on June 23, 1993 (58 FR 34126) and July 30, 1993 (58 FR 40746–40752). A notice of direct final rulemaking and of interim final rulemaking further amending the regulations was published on May 17, 1995 (60 FR 26510 and 60 FR 26560). Subsequently, on November 20, 1996, a final rule was published in response to public comments received on the direct final and interim rules (61 FR 59142–59166) .

The issues addressed by this proposed rule are: (1) revised definitions of gas-fired, oil-fired, and peaking unit to allow for changes in unit fuel usage and/or operation; (2) a minor wording correction of the applicability provisions in Part 72; (3) new excepted methodologies for units with low mass emissions; (4) new QA/QC requirements for moisture monitoring systems; (5) clarifying changes to the certification and recertification process; (6) substitute data requirements for CO_2 and heat input, as well as a prohibition against low data availability; (7) clarifying revisions to the petition provisions for alternatives to part 75 requirements; (8) NO_X mass monitoring provisions provided as a model for adoption by state, tribal, or federal NO_X mass reduction programs; (9) clarifying changes to span and range requirements; (10) clarifying revisions to general QA/QC requirements; (11) calibration gas concentrations for daily calibration error tests; (12) linearity test requirements; (13) a new flow-to-load QA test for flow monitors; (14) reductions in and/or clarifications to the relative accuracy test audit (RATA) and bias test requirements; (15) clarifying revisions to the procedures for CEM data validation; (16) clarifying revisions to the SO_2 emissions data protocol for gas-fired and oil-fired units (Appendix D); (17) determining CO_2 emissions (Appendix G, sections 2.1 and 5); (18) recordkeeping and reporting changes to reflect the proposed revisions; (19) a revised traceability protocol (Appendix H); and (20) a new optional F-factor/fuel flow method (Appendix I). In addition, the preamble also includes a discussion on potential provisions to allow for the use of predictive emissions modeling systems (PEMS) as an alternative to CEMS for certain units.

Many of the changes proposed today are minor technical revisions based on comments received from utilities following the initial implementation of part 75. Based on experience gained in the early years of the program, utilities have developed a number of suggestions that EPA believes would simplify and streamline the monitoring process without sacrificing data quality. In addition, the Agency is proposing to reduce the monitoring requirements for units with low mass emissions to reduce burdens on those types of units and to add new monitoring options for some units. The Agency has also proposed new quality assurance requirements based on gaps identified by EPA during evaluation of the initial implementation of part 75. Finally, several minor technical changes are also proposed in order to maintain uniformity within the rule itself and to clarify various provisions.

III. Detailed Discussion of Proposed Revisions

A. Use of Projections in the Definitions of Gas-Fired, Oil-Fired, and Peaking Unit

Background

Section 72.2 of the January 11, 1993 rule provides definitions for the terms ''gas-fired,'' ''oil-fired,'' and ''peaking unit.'' Each definition provides a limit on the fuel usage or capacity factor averaged over a three year period, as well as an individual limit on each of the three years, in order to qualify under the definition. The May 17, 1995 revisions to part 75 amended those definitions by adding provisions for how a unit would initially qualify to meet the definition. Each definition provides for the case where a unit has three years of historical data demonstrating qualification, as well as the case where a unit does not have data for one or more of the three previous years (e.g., a new unit or a unit that has been in an extended shutdown). In addition, the gas-fired definition provides for the case where a unit's fuel usage is projected to change on or before January 1, 1995 and the peaking unit definition provides for the case where a unit's capacity factor is projected to change on or before the certification deadline (either 1995 or 1996) for NO_X

monitoring in § 75.4. In each case where historical data does not exist or is not representative based on projected change, the amended definitions set provisions for allowing projections of unit operation to be used in place of historical data in order to meet the criteria of the respective definition. However, none of the three definitions provides for the case where a unit's fuel usage or capacity factor is expected to change after initial classification.

Under the existing rule, the importance of determining whether a unit qualifies under the definitions of gas-fired, oil-fired, and peaking unit, centers on the differences in regulatory requirements and options for different classifications of units. For example, under § 75.11(d)(2), a unit that qualifies as gas-fired or oil-fired has an additional option for monitoring SO_2 emissions using the excepted protocol of Appendix D, in lieu of an SO_2 CEMS and flow monitor. Additionally, under § 75.14(c), a unit that qualifies as gas-fired is exempt from opacity monitoring, and, under section 2.3 of Appendix G to part 75, a gas-fired unit has an additional option for determining CO_2 mass emissions in lieu of a CO_2 CEMS or using carbon sampling in conjunction with a fuel flowmeter. Qualifying under the definition of peaking unit also has the advantage of allowing additional regulatory options. For example, a peaking unit has the option of monitoring NO_X emission rate using the excepted protocol under Appendix E, in lieu of a NO_X CEMS. Further, under section 2.3.1 of Appendix B to part 75, a peaking unit is required to perform annual quality assurance flow monitor RATAs at a single load level instead of at three load levels.

Utility representatives have contacted EPA for guidance about how a change in the manner of operation of the unit after certification and initial classification of the unit affects the status of the unit with respect to the definitions of gas-fired, oil-fired, and peaking unit. For example, a utility representative contacted the Agency about a unit designed to burn gas and/or oil that historically had burned primarily oil and was classified as an oil-fired unit. The utility had decided to switch from oil to burn almost entirely gas at the unit and asked whether it was necessary to wait three years after the switch to gas in order to gather three years of historical data, to qualify for the additional regulatory options available only for gas-fired units. The utility requested permission to use projections of fuel usage certified by the designated representative, to demonstrate that the unit would meet the gas-fired definition after the switch to gas, so that the unit could be exempt from opacity monitoring and qualify to use equation G–4 to determine CO_2 mass emissions. The existing rule would require such a unit to wait three years after the change in operation in order to qualify as gas-fired. Based on EPA's experience of implementing the provisions of Parts 72 and 75, the definitions of the terms gas-fired, oil-fired, and peaking unit are not sufficiently detailed or flexible to address situations where a permanent change in the manner of operation after the initial classification (i.e, capacity factor or fuel usage) affects the gas-fired, oil-fired, or peaking unit status.

Discussion of Proposed Changes

Today's proposal would amend the definitions of the terms gas-fired, oil-fired, and peaking unit, to add provisions for an existing unit that does not presently qualify under the definition but that experiences a permanent change in operation (i.e., fuel usage for the gas-and oil-fired definitions and capacity factor for the peaking unit definition).

For the definition of gas-fired, the proposed revisions would allow an existing unit to qualify under the definition if the designated representative submits a minimum of 720 hours of unit operating data demonstrating that the unit meets the percentage criteria of a gas-fired unit (i.e., no less than 90.0 percent of the unit's heat input from the combustion of gaseous fuels with a total sulfur content no greater than natural gas and the remaining heat input from the combustion of fuel oil), accompanied by a certification statement from the designated representative. The designated representative statement would certify that the changed pattern of fuel usage, represented in the 720 hours of data, is considered permanent and is projected to continue for the foreseeable future.

The proposed definition of oil-fired unit would simplify the provisions for qualification, for purposes of part 75. The proposed definition would simply require that a unit burn only fuel oil and gaseous fuels with a total sulfur content no greater than natural gas and that the unit does not meet the definition of gas-fired, in order to qualify as oil-fired. With this simplification, a unit could qualify under any of the following circumstances: (1) a new unit projected to burn only fuel oil and gaseous fuels with a sulfur content no greater than natural gas but projected to burn too much oil to qualify as gas-fired; (2) an existing gas-fired unit, which burns only fuel oil and natural gas, but which exceeds the gas-fired annual limit of 15 percent of the annual heat input from fuel oil; and (3) an existing coal-fired unit that is converted to only burn fuel oil and/or gas but which projects it will burn too much oil to qualify as gas-fired.

The proposed definition of peaking unit would allow an existing unit whose capacity factor is projected to change, to qualify as a peaking unit if the designated representative submits a demonstration satisfactory to the Administrator that the unit will qualify as a peaking unit, using the three calendar years beginning with the first full year following the change in the unit's capacity factor as the three year period. This demonstration would need to show that the unit's capacity factor in the year following the permanent change in operation did not exceed 10.0 percent and that the projected average annual capacity factor for the unit in the three year period and the projected capacity for each of the two individual projected years will meet the definition of a peaking unit.

Additionally, under today's proposal, the gas-fired definition would be revised to clarify the requirements as they apply for the purposes of part 75 versus the requirements for the purposes of all other Parts under the Acid Rain Program. This proposed revision is merely editorial and would not change the intent of the existing regulation.

Rationale

The Agency proposes to allow projections of fuel usage or capacity factor in conjunction with some actual data to be used for the purpose of meeting the criteria of the gas- or oil-fired or peaking unit definitions, respectively. The Agency believes it is unnecessary to require three years to pass before a unit that the designated representative certifies has permanently changed its manner of operation is allowed to utilize the additional regulatory options allowed for units meeting the definitions of gas-fired, oil-fired, and peaking unit. The Agency believes it is sufficient to require the designated representative to submit representative data that the unit would qualify under the definition following the permanent change in operation or fuel usage (i.e., 720 hours for the gas-fired definition and a full year for the peaking unit definition) and to certify that the change in fuel usage or capacity factor is considered permanent and that the unit is expected to continue to meet the definition of gas-fired, oil-fired, or peaking unit, as applicable, into the foreseeable future.

Under the existing rule, the peaking unit definition does provide for the

situation where a unit's operation is projected to change and the unit will meet the peaking unit definition with those projections. However, this provision is limited to the case where a unit's operation has changed by the certification deadline for NO_X monitoring. The existing rule does not provide for the scenario where a change to the unit's operation after the certification deadline would affect the peaking unit status and where the designated representative might want to take advantage of regulatory options that are available under this new status.

EPA believes that it is appropriate to allow a unit to use the regulatory options that are only allowed for peaking units, if a unit's operation permanently changes such that it meets the capacity factor definition with one year of actual data and two years of projections. If the projections are incorrect, the unit will lose its peaking unit status and will not be able to use projections again to qualify.

Similarly, under the existing rule, the gas-fired definition does provide for the situation where an existing unit that does not qualify under the gas-fired definition experiences a change in operations or fuel usage that would result in the unit qualifying as gas-fired in future years. However, this provision is limited to the case where a unit's operation has changed by the certification deadline for SO_2 and opacity monitoring, from 1995 through 1997. The existing rule does not provide for the scenario where a change to the unit's fuel usage after the certification deadline would affect the gas-fired status and that the designated representative might want to take advantage of regulatory options that are available under this new status.

However, EPA believes that it is appropriate to allow a unit to use the regulatory options that are only allowed for gas-fired units, if a unit's fuel usage permanently changes such that it meets the gas-fired definition with 720 hours of actual data and projections of fuel usage to make up the remainder of the three year period. If the projections are incorrect, the unit will lose its gas-fired status and will not be able to use projections again to qualify.

B. Wording Correction of the Applicability Provisions in Part 72

Background

Section 72.6(b)(1) currently includes, in the list of types of units that are unaffected units under the Acid Rain Program, ''[a] simple combustion turbine that commenced operation before November 15, 1990.'' 40 CFR 72.6(b)(1). Title IV actually provides, through statutory definitions and provisions setting emission limitations, that a simple combustion turbine that commenced *commercial* operation before the enactment of title IV, i.e., November 15, 1990, is an unaffected unit. A simple combustion turbine commencing commercial operation on or after November 15, 1990 is an affected unit (unless it is exempt under some other provision, e.g., the new units exemption under § 72.7).

To begin, the definition of ''existing unit'' in section 402(8) of the Act excludes existing simple combustion turbines (i.e., those that commenced commercial operation prior to November 15, 1990) and so excludes them from being affected units subject to an SO_2 emission limitation under section 405(a)(1). As stated in that section 402(8):

> ''existing unit'' means a unit * * * that commenced commercial operation before the date of enactment of the Clean Air Act Amendments of 1990 [i.e., November 15, 1990] * * * For purposes of this title, existing units shall not include simple combustion turbines * * * 42 U.S.C. 7651a(8).

In contrast, the statutory definition of ''new unit'' does not exclude any new simple combustion turbines, and under section 403(e), all new utility units are affected units subject to an SO_2 emission limitation. As stated in section 402(10):

> ''new unit'' means a unit that commences commercial operation on or after the date of enactment of the Clean Air Act Amendments of 1990 [i.e., November 15, 1990]. 42 U.S.C. 7651a(10).

A unit that commences commercial operation *after* November 15, 1990, and so does not meet the definition of ''existing unit'', is therefore a new unit and an affected unit subject to Acid Rain Program requirements.

While § 72.6(b)(1) states that a simple combustion turbine that ''commenced operation'' before November 15, 1990 is not an affected unit, EPA interprets this provision, consistent with the Act, to refer to commencement of commercial operation. However, in order to remove any ambiguity and any possibility of erroneous application of the statutory exemption for simple combustion turbines, EPA believes that the regulatory provision should be corrected.

Discussion of Proposed Changes

Today's proposal would revise the existing § 72.6(b)(1) in order to make it consistent with title IV of the Act. EPA proposes to revise the language of the provision to refer expressly to ''commercial operation,'' rather than simply ''operation,'' of a simple combustion turbine.

Rationale

EPA notes that the existing § 72.6(b)(1) was not intended to deviate from the provisions in the Act concerning simple combustion turbines. In proposing the applicability provisions that were finalized (with changes) as § 72.6, EPA explained that:

> simple combustion turbines would be subject to Acid Rain Program requirements in Phase II (as new units) if such units commenced commercial operation on or after November 15, 1990, because the statutory exemption for simple combustion turbines is only applicable to existing units. 56 FR 63002, 63008 (1991).

In noting that new simple combustion turbines are affected units, EPA requested comment on whether a ''*de minimis* exclusion should be included in the final rule'' for ''very small units'' from the Acid Rain Program. *Id.* In response to comments supporting an exemption for simple combustion turbines and other units, EPA established in the final rule an exemption for new units (including new simple combustion turbines) serving generators with total capacity of 25 MWe or less. 58 FR 3590, 3593–4 (1993); Response to Comment at P–22 and P–23 (1993). In the final rule preamble, EPA did not indicate any intention to make any other changes concerning the applicability of the Acid Rain Program to new simple combustion turbines.

C. Low Mass Emissions Excepted Methodology

Background

In the January 11, 1993 Acid Rain permitting rule, EPA provided for a conditional exemption from the emissions reduction, permitting, and emissions monitoring requirements of the Acid Rain Program for new units having a nameplate capacity of 25 MWe or less that burn fuels with a sulfur content no greater than 0.05 percent by weight, because of the *de minimis* nature of their emissions (see 58 FR 3593–94 and 3645–46). Moreover, in the January 11, 1993 monitoring rule, EPA allowed gas-fired and oil-fired peaking units to use the provisions of Appendix E, instead of CEMS, to determine the NO_X emission rate, stating that this was a *de minimis* exception. EPA allowed this exception from the requirements of section 412 of the Clean Air Act because the NO_X emissions from these units would be extremely low, both

collectively and individually, and because the cost of measuring a ton of NO_X with CEMS could be several hundred dollars per ton of NO_X monitored (see 58 FR 3644–45). One utility wrote to the Agency, suggesting that the Agency consider further regulatory relief for other units with extremely low emissions that do not fall under the categories of small new units burning fuels with a sulfur content less than or equal to 0.05 percent by weight or gas-fired and oil-fired peaking units (see Docket A–97–35, Item II–D–31). The utility specifically suggested that the Agency consider an exemption, the ability to use Appendix E, or some other simplified methods which are more cost effective.

In the process of implementing part 75, other utilities also have suggested to EPA that it provide regulatory relief to low mass emitting units (see Docket A–97–35, Items II–D–29, II–E–25). These units might be low mass emitting because they use a clean fuel, such as natural gas, and/or because they operate relatively infrequently. Some utilities stated that they spend a great deal of time reviewing the emissions data when preparing quarterly reports for these units. Others indicated that it would be important to reduce monitoring and quality assurance (QA) requirements in order to save time and money currently devoted to units with minimal emissions (see Docket A–97–35, Item II–E–25).

Discussion of Proposed Changes

Today's proposal would incorporate optional reduced monitoring, quality assurance, and reporting requirements into part 75 for units that burn only natural gas or fuel oil, emit no more than 25 tons of SO_2 and no more than 25 tons of NO_X annually, and have calculated annual SO_2 and NO_X emissions (reflecting their potential emissions during actual operation) that do not exceed such limits.

A unit would initially qualify for the reduced requirements by demonstrating to the Administrator's satisfaction that the unit meets the applicability criteria in proposed § 75.19(a). Proposed § 75.19(a) would require facilities to submit historical actual (or projections, as described below) and calculated emissions data from the previous three calendar years demonstrating that a unit falls below the 25-ton cutoffs for SO_2 and NO_X. The calculated emissions data for the previous three calendar years would be determined by applying the emission factors and maximum rated hourly heat input, under § 75.19(c), to the hours of operation and fuel burned during the previous three calendar years. The data demonstrating that a unit meets the applicability requirements of § 75.19(a) would be submitted in a certification application for approval by the Administrator to use the low mass emissions excepted methodology. The Agency requests comments on whether a unit that exceeded the 25-ton emissions cutoff for a part of the previous three years, but that has made a permanent change in the operation of the unit such that it would expect to meet the applicability criteria based on projections of future operation, should be allowed to use the excepted methodology.

For units that lack historical data for one or more of the previous three calendar years (including new units that lack any historical data), proposed § 75.19(a) would require the facility to provide (1) any historical emissions and operating data, beginning with the unit's first calendar year of commercial operation, that demonstrates that the unit falls under the 25-ton cutoffs for SO_2 and NO_X, both with actual emissions and with calculated emissions using the proposed methodology, as described above; and (2) a demonstration satisfactory to the Administrator that the unit will continue to emit below the tonnage cutoffs (e.g., for a new unit, applying the emission rates and hourly heat input, under § 75.19(c), to a projection of annual operation and fuel usage to determine the projected mass emissions).

For units with historical actual (or projections, as described above) emissions and calculated emissions falling below the tonnage cutoffs, facilities would be allowed to use the optional methodology in proposed § 75.19(c) in lieu of either CEMS or, where applicable, in lieu of the excepted methods under Appendix D, E, or G for the purpose of determining and reporting heat input, NO_X emission rate, and NO_X, SO_2, and CO_2 mass emissions. Under the optional methodology in proposed § 75.19(c), a facility would calculate and report hourly SO_2 and CO_2 mass emissions based on the unit's maximum rated hourly heat input and the appropriate emission factor, defined in § 75.19(c), Tables 1a and 1c, for the fuel burned that hour. Similarly, a facility would calculate and report hourly NO_X mass emissions as the product of the maximum rated hourly heat input and the appropriate fuel and boiler type NO_X emission rate located in proposed Table 1b. The facility would no longer be required to keep monitoring equipment installed on low mass emissions units, nor would it be required to meet the quality assurance test requirements or QA/QC program requirements of Appendix B to part 75. Moreover, emissions reporting requirements would be reduced by requiring only that the facility report the unit's hourly mass emissions of SO_2, CO_2, and NO_X, the unit's NO_X emission rate, and the fuel type burned for each hour of operation, and report the quarterly total and year-to-date cumulative mass emissions, heat input, and operating time, in addition to the unit's quarterly average and year-to-date average NO_X emission rate for each quarter. Facilities would continue to be required to monitor, record, and report opacity data for oil-fired units, as specified under §§ 75.14(a), 75.57(f), and 75.64(a)(iii) respectively. Under § 75.14(c) and (d), however, gas-fired, diesel-fired, and dual-fuel reciprocating engine units would continue to be exempt from opacity monitoring requirements.

If an initially qualified unit were subsequently to burn fuel other than natural gas or fuel oil, the unit would be disqualified from using the reduced requirements starting the first date on which the fuel (other than natural gas or fuel oil) was burned.

In addition, if an initially qualified unit were to subsequently exceed the 25-ton cutoff for either SO_2 or NO_X while using the proposed methodology, the facility would no longer be allowed to use the reduced requirements in proposed § 75.19(c) for determining the affected unit's heat input, NO_X emission rate, or SO_2, CO_2, and NO_X mass emissions. Proposed § 75.19(b) would allow the facility two quarters from the end of the quarter in which the exceedance of the relevant 25-ton cutoff(s) occurred to install, certify, and report SO_2, CO_2, and NO_X data from a monitoring system that meets the requirements of §§ 75.11, 75.12, and 75.13, respectively.

Rationale

In addressing concerns from utilities about the cost of monitoring, quality assurance testing, and reporting emissions from low-emitting sources, EPA considered how to establish reduced requirements. Utilities have indicated to EPA that it would be more helpful for the Agency to reduce testing requirements for monitoring equipment than it would be to reduce only reporting requirements (see Docket A–97–35, Item II–E–25). The Agency considered whether a reduction in monitoring or reporting requirements might have unintended adverse consequences for the environment. In order to minimize this possibility, but still make the program more cost

effective for facilities, the Agency is proposing to allow an exception from full monitoring and reporting requirements for low mass emitting units. In proposing these reduced requirements, the Agency is exercising its discretion to allow *de minimis* exceptions from statutory requirements in administering the Clean Air Act (see, e.g., *Alabama Power Co.* v. *Costle,* 636 F.2d 323, 360–61 (D.C. Cir. 1979); and 58 FR 3593–94 and 3645–46). The Agency, in exercising its discretion, believes that in light of the *de minimis* aggregate amount of emissions from low-emitting units as a group, little or no environmental benefit would be derived from continuing to require the additional accuracy of monitoring data from low-emitting units under the existing regulations, if such units are subjected instead to the proposed optional requirements. EPA also notes that any such benefit would be greatly outweighed by the cost of providing the more accurate data.

In drafting today's proposal, the Agency considered six relevant questions: (1) What parameters should the applicability criteria be based on? (2) How should estimated emissions be calculated? (3) What cutoff emission level should be used to determine applicability of the reduced requirements? (4) What should the on-going applicability requirements be? (5) What should the reduced monitoring and quality assurance requirements be for these units? and (6) What should the recordkeeping and reporting requirements be for these units?

1. Applicability Criteria

The Agency believes that the initial criteria for a unit to qualify for the excepted monitoring should be consistent with the on-going criteria for using such monitoring so that only units that can likely continue to use the methodology will qualify in the first place. With the reduced monitoring requirements under this exception, a unit will not need to install monitors. Consequently, the Agency believes that the on-going applicability criteria should not depend on measurements from emissions monitoring equipment and that actual emissions data or actual heat input data, which are measured by the monitoring equipment, would not be appropriate as the primary applicability criteria for initial qualification for the exception or as the criteria for on-going qualification.

The Agency considered what criteria, other than actual measurements, should be used as a basis for determining applicability to use the reduced monitoring and reporting exception. EPA considered various parameters to use in the applicability criteria, including: estimated emissions or heat input, the fuel burned, the unit capacity factor, and annual generation measured in MW-hr. Because the Agency's objectives for the exception include ensuring that the total emissions from the group of units that would qualify under the exception are *de minimis* and allowing more cost effective monitoring for units in such a group, the Agency believes it would be preferable to base the applicability on estimated emissions. While it may be simpler to base qualification for reduced monitoring *solely* on the fuel burned, the unit capacity factor, or the annual generation than to estimate the emissions, the Agency believes that it would be more difficult under that approach to ensure that total emissions that qualify under the exception were *de minimis*. The Agency further believes that using any of the other parameters, while attempting to ensure that the total emissions from the group are *de minimis,* might exclude some units that actually have low emissions. For example, a unit that burns mostly natural gas with emergency oil would be excluded from an exception limited to units that burn only natural gas. The Agency believes that an applicability criteria based on emissions would relate more directly to the objectives behind the optional exception than would other operating factors that might serve as a proxy for emissions.

2. Method for Determining Emissions

The Agency considered several methods for determining the estimated emissions as the basis for applicability of the reduced monitoring and reporting excepted methodology. For each of the methods considered, rather than using actual measured sulfur and carbon values, CO_2, SO_2, and flow CEM readings, NO_X CEM readings, or NO_X values from an Appendix E NO_X-versus-heat input correlation, a facility would calculate the unit's emissions based on an emission rate factor and default heat input. Since the units that would qualify for the excepted methodology would still be accountable for reporting emissions to the Agency and surrendering allowances based on those emissions, where applicable, the emissions estimations would not just be used to determine if the unit qualifies under the exception; the reported estimations would also be used to determine compliance. The Agency considered its goals for emissions accounting in order to establish the emission rate factors and default heat input. The Agency maintains that it would be inappropriate to select values that would potentially underestimate emissions, thereby undermining the Agency's ability to determine compliance and achieve emission reductions under title IV or any other regulatory program involving SO_2, CO_2, or NO_X. Some industry representatives suggested that facilities would be willing to use a conservative emission estimate, such as a maximum potential emission rate times the maximum heat input, if it would allow them to save time and money currently spent on monitoring and quality assurance (see Docket A–97–35, Items II–D–30, II–D–43, II–D–45, II–E–13, and II–E–25).

The Agency explored basing the estimated emissions on a unit's maximum potential emissions, i.e., converting the unit's nameplate capacity (which assumes maximum possible operation) to a maximum annual heat input for the unit and multiplying by the unit's maximum emission rate (which assumes the highest emission rate of all fuels capable of being burned at the unit). This option would have several advantages. It would ensure that emissions are not underestimated, would allow for reduced monitoring requirements, and would ensure that a unit that initially qualifies for the exception would continue to qualify without having to reevaluate the unit's emissions each year (unless some modification was made to the unit to increase its nameplate capacity or allow a higher emitting fuel to be burned). This approach, however, would likely disqualify gas-fired units that sometimes burn oil or peaking units that operate infrequently, since maximum potential emissions would be substantially higher than their actual emissions and would likely exceed the applicability criteria limit. Using this method to estimate emissions for purposes of an applicability cutoff would greatly diminish the usefulness of the reduced requirements and would fail to fully meet the intended purpose of today's proposal.

In place of using a heat input derived from maximum possible operation (i.e., nameplate capacity), the Agency considered estimating heat input by multiplying the actual operating hours times a maximum rated hourly heat input for the unit. While this would require re-evaluation of a unit's eligibility each year, this would allow an infrequently operated peaking unit to qualify if its emissions are low, which EPA believes is worth the additional burden of annual re-evaluation. Therefore, the Agency is proposing to use maximum rated hourly heat input as the heat input in the emissions

estimation. Maximum rated hourly heat input would be defined, in § 72.2, as a unit-specific maximum hourly heat input (mmBtu) based on the manufacturer's rating of the unit or, if that value has been exceeded in practice, based on the highest observed hourly heat input. In addition, there would be provisions for a lower maximum hourly heat input to be used if the unit has undergone modifications which permanently limit its capacity.

The Agency also considered what emission rate(s) to apply, instead of using the highest emission rate of all fuels capable of being burned at the unit, in order to avoid underestimation and to allow a unit that primarily burns gas but has the ability to burn oil to qualify for the reduced requirements. The Agency believes that it would be appropriate to use emission rates based on uncontrolled emissions for the actual fuel burned in any given hour to estimate emissions for purposes of the initial and on-going applicability cutoffs to qualify to use the low mass emissions excepted methodology and for purposes of emissions reporting, allowance accounting, and compliance. This approach would avoid disqualifying gas-fired units simply because of their occasional use of oil and would also avoid underestimating emissions.

For determining SO_2 mass emissions using the low mass emissions methodology, EPA proposes the use of emission factors in lb/mmBtu based on its AP–42 air pollution emission rate factors, which are established from the sulfur content and gross calorific value of the fuel being burned (see Docket A–97–35, Items II–A–11, II–I–1). Since the SO_2 emissions are directly proportional to the amount of sulfur in the fuel and in light of the limited variability in the sulfur content of natural gas and oil, the proposed SO_2 mass emission factors should be fairly representative of uncontrolled, actual emissions. Because of the relatively low sulfur content of natural gas or oil, it is doubtful that any of such units have SO_2 controls. The proposed factors fall within the typical range of sulfur content and gross calorific value for each fuel, although somewhat on the conservative side for sulfur content of diesel fuel and natural gas other than pipeline natural gas.

For determining NO_X mass emissions and emission rate, EPA proposes using the fuel- and unit-type-specific NO_X emission rate factors based on 90th percentile emission rate data reported under part 75 generally for uncontrolled units (see Docket A–97–35, Item II–A–9). While attempting to develop an accounting approach for NO_X emissions from low mass emission units, EPA encountered several issues. The first issue involves the use of AP–42 factors. During the finalization of the core part 75 monitoring rule, EPA considered allowing peaking units with negligible emissions both individually and collectively to estimate NO_X emissions using AP–42 emission rate factors. EPA rejected this approach in the January 11, 1993 final rule preamble at 58 FR 3644–45 because the AP–42 emission rate factors are derived from industry-wide average estimates of emissions for different fuel and boiler types and are not based on actual historical operating experience of the units to which the estimates would be applied. Applying AP–42 factors could result in underestimation of NO_X emissions because actual NO_X emissions can vary significantly from unit to unit. The formation of NO_X from the combustion of fossil fuels is dependent on the amount of nitrogen in the fuel being combusted and on the mix of nitrogen and oxygen in combustion air. Further, the NO_X formation process depends on unit-specific factors of combustion gas temperature and stoichiometry of fuel and air local to the flame. Consequently, there can be significant variations in the level of NO_X emissions from unit to unit due to variations in combustion conditions. Therefore, EPA is not proposing the use of AP–42 factors to estimate NO_X emissions from low mass emissions units. Instead, now that three years of actual historical operating data collected under part 75 are available, it was possible to develop the default NO_X emission rate factors being proposed today. Although the default NO_X emission rate factors in today's proposal are generic factors, they should not underestimate NO_X emissions because they are based on the 90th percentile of actual annual average emission rates reported generally from uncontrolled units under part 75.

The Agency also considered using site-specific NO_X emission rate factors based on historical emission data or emissions testing data for the unit. For example, a facility might use the maximum value ever recorded by the CEM for the unit, or it might use the highest NO_X emission rate value calculated from the unit's most recent Appendix E NO_X test, or it might use site-specific values similar to those discussed in the guidance manual for implementing the NO_X budget program in the OTR (see Docket A–97–35, Item II–I–7). The application of site-specific NO_X emission factors for low mass emission units raises several issues. First, for units with pollution controls where the emission factor is based on controlled emissions, the site-specific emission factor could underestimate actual emissions if the controls are not operating properly. EPA considered only allowing site-specific NO_X emission factors with units that do not utilize NO_X emission controls; however, EPA realizes that many units employ at least some form of NO_X emission controls (e.g., water or steam injection). EPA also considered allowing a source with controls to use a site-specific emission factor only if it could demonstrate that the pollution controls are operating properly. However, this would involve extensive, additional recordkeeping and tracking to verify the proper operation of pollution controls and ensure that emissions are not underestimated; this would run contrary to the general approach under the exception of reducing monitoring and reporting requirements. A second issue involves verifying that the site-specific NO_X emission factor is still representative over time or after unit modifications. This would require future NO_X emission rate testing. Therefore, for purposes of creating a methodology that is simple to implement and in order to reduce future testing requirements for facilities with low mass emitting units, the Agency proposes instead using NO_X emission rate factors based on fuel and unit type and reflecting uncontrolled emissions. EPA requests comments on this approach, whether other approaches should be used, and especially whether there are any additional boiler types not represented in today's proposed rule for which NO_X emission rates should be provided.

For determining CO_2 mass emissions, today's rule proposes to use CO_2 emission rate factors in tons/mmBtu. The CO_2 emission rate factors are derived based on ideal gas theory and standard Agency F_c factors for estimating the volume of CO_2 to be emitted when a certain heat input of a particular fuel is burned (see Docket A–97–35, Item II–A–11). This resembles the approach currently used in Equation G–4 of Appendix G for gas-fired units.

Therefore, the Agency believes that an appropriate method of estimating emissions for the purposes of qualifying for a reduced monitoring and reporting exception and for purposes of emissions accounting and compliance for units under the exception is to calculate emissions based on the actual number of operating hours and the actual fuel burned using maximum rated hourly heat input and fuel-based and, for NO_X unit-type-based, emission factors. The Agency requests comments on this approach and on whether an alternate

approach should be used. While the Agency believes that the resulting emissions estimates will in most, if not all, cases be conservative and result in an overestimation of emissions, it would be possible, however unlikely, that the estimate could underestimate the actual emissions for some types of units. Therefore, for existing units with historical emissions data available, the proposal would require that in addition to meeting the applicability criteria using the emissions estimates calculated as described above, the unit would have to meet the cutoffs for initial qualification for the exception using the actual annual emissions monitored during the three years prior to applying to use the exception.

3. Cutoff Limit for Applicability

EPA began developing applicability criteria by first considering the level of projected aggregate emissions determined to be *de minimis* for purposes of developing the new unit exemption promulgated in the January 11, 1993 Acid Rain permitting rule (*see* 58 FR 3593–94 and 3645–46). Aggregate emissions projected for units under the exemption were approximately 138 cumulative tons of SO_2 and 1934 cumulative tons of NO_X emitted per year. The Agency then conducted a study of actual emissions data from 1996 quarterly reports under part 75 and evaluated potential tonnage cutoffs for SO_2 and NO_X. The Agency compared the cumulative mass emissions from groups of units emitting less than various specified amounts to the total emissions reported under the Acid Rain program during the year (see Docket A–97–35, Item II-A–10). For example, the study shows what proportion of total SO_2 was emitted by units with both actual and potential [1] emissions of 25 tons or less per year, 50 tons or less per year, 60 tons or less per year, and 75 tons or less per year. From these analyses, EPA also estimated how many units might be eligible for reduced requirements for determining emissions and how much of an impact the new emissions accounting option would have on nationwide emissions accounting.

EPA is proposing cutoff values of 25 tons per year of SO_2 and 25 tons per year of NO_X. In order to qualify as a low mass emissions unit, a unit would have to demonstrate that both actual historical emissions and potential emissions (calculated with maximum hourly heat input, emission factors and either, for existing units, actual historical number of operating hours or, for new units, projections of future annual operating hours) do not exceed 25 tons each for SO_2 and NO_X on an annual basis. Based upon its analyses (see Docket A–97–35, Item II-A–10), EPA estimates that this tonnage cutoff level would mean that the group of units subject to the proposed reduced requirements, even after Acid Rain Program emission reductions are considered, would have total annual emissions of about 16 tons of SO_2 and 90 tons of NO_X (less than a thousandth of a percent of total annual SO_2 emissions and about 0.002 percent of total annual NO_X emissions for all affected units). Both amounts, 16 tons of SO_2 and 90 tons of NO_X, are less than the total number of tons of those pollutants determined to be *de minimis* for purposes of the new unit exemption. Today's proposal to treat low mass emission units as *de minimis* is consistent with the *de minimis* conclusions reached for new units.

While the reduced requirements are somewhat less accurate than the methodologies under the existing regulations, the reduced requirements are intended to yield emissions data that are conservative and that, to the extent they are inaccurate, are likely to overstate emissions. Moreover, EPA believes that the level of inaccuracy (i.e., overstatement of emissions) would similarly be extremely low (i.e., less than a thousandth of a percent). Both the total emissions subject to the reduced requirements and the potential amount of overstatement of emissions are *de minimis*. Moreover, any overstatement of regulated emissions would have the effect of tightening emission limits (e.g., by requiring surrender of more allowances for SO_2 than otherwise). Any overstatement of other emissions would be too small to affect adversely the air quality related activities (e.g., air quality modeling) for which the emissions data would be used.

EPA would, however, be concerned about extending today's proposed reductions in monitoring, quality assurance, and reporting requirements to units that exceed the 25-ton cutoffs for actual or potential emissions. Section 412 of the CAA requires all affected units to monitor SO_2, volumetric flow, NO_X, and opacity using continuous emission monitoring systems or an alternative monitoring system approved by the Administrator as having the same precision, reliability, accessibility, and timeliness. In addition, section 412 of the Act requires that emissions data be quality-assured. Section 821 of the Clean Air Act Amendments of 1990 provides that, through regulations issued by the Administrator, all affected units must be required to monitor CO_2 emissions in the same manner and to the same extent as SO_2 and NO_X are monitored under section 412. Part 75 of EPA's rules requires monitoring of SO_2, NO_X, and CO_2 and allows certain exceptions to the statutory requirement for CEMS or CEMS-equivalent alternative monitoring: in Appendix D because, *inter alia*, the information gathered using the Appendix D methods is as precise, reliable, accessible, and useful as that from CEMS, and compares acceptably with regard to timeliness; and in Appendix E because the emissions from all units eligible to use Appendix E are negligible and such units do not have emission limitations for NO_X under the Acid Rain Program (see 58 FR 3641–45). The proposed reduced monitoring and reporting requirements for low mass emissions units would not yield information equivalent to that from CEMS. EPA must balance the benefits of reduced monitoring, quality assurance, and reporting requirements for units against the intent of the statute that monitoring with CEMS or their equivalent be required so as to obtain reliable, precise, timely, and readily accessible information on emissions. EPA solicits comment on whether 25 tons is the appropriate cutoff level for applicability of the low mass emission excepted methodology.

In particular, EPA is concerned that extending the proposed reduction in requirements to units with more than this *de minimis* level of emissions could have a negative impact on the environment. Emissions data from the Acid Rain Program are being used for a variety of efforts, including emissions modeling and establishing baseline emissions information (prior to any emission reductions) for new air pollution control programs. Using less accurate methods to monitor more than a *de minimis* amount of emissions could potentially undermine efforts to establish baseline emissions and to assess what emission reductions have already taken place and how much further emissions must be reduced in order to meet air quality standards.

Furthermore, with regard to coal-fired units, such units account for the largest proportion of all emissions, tend to be operated more frequently, and generally have much higher emission rates in lb/mmBtu for SO_2, NO_X and CO_2, and the majority of the units have emission limitations and emission reduction

[1] The terms ''potential emissions'' used in this section of the preamble have a different meaning than the terms ''potential to emit'' used elsewhere by the Agency.

requirements for SO_2 and NO_X. In addition, the sulfur content in coal and gaseous fuels other than natural gas is much more variable than for natural gas and oil, and the emission factors for coal or gaseous fuels other than natural gas, particularly an SO_2 emission factor, are therefore less reliable and much more likely to understate, rather than overstate, emissions. Based on these considerations, the proposed rule would restrict the use of the reduced requirements to gas-fired units and oil-fired units that burn natural gas and/or fuel oil.

In order to qualify for the proposed low mass emissions excepted methodology, the proposed applicability criteria would require a unit to meet annual tonnage cutoffs of 25 tons each for SO_2 and NO_X. EPA considered whether the excepted methodology should be available on a pollutant specific level so that, for example, a unit which falls below the tonnage cutoff for SO_2 but not for NO_X could use the proposed excepted methodology under § 75.19 to measure SO_2 emissions but use a NO_X CEM or the excepted methodology under Appendix E, where applicable, to measure NO_X emissions. EPA believes this approach would not be appropriate because some of the same monitoring equipment and reporting software is necessary for measuring and reporting both of the pollutants. One of the prime benefits of the low mass emissions excepted methodology would be the simplified reporting which would require less time and a less sophisticated Data Acquisition and Handling System. In particular, the need for a DAHS that could calculate substitute data using the missing data algorithms would be removed because there are no missing data algorithms for the low mass emissions excepted methodology. If the excepted methodology is only applied to one of the pollutants, much of the benefit would be negated because the DAHS would still need to be capable of calculating substitute data for the measured pollutant and close to the full quarterly report would still be required. Another prime benefit of the proposed low mass emissions excepted methodology would be the removal of monitoring and quality assurance requirements. However, EPA believes that almost all units that would qualify for a 25-ton cutoff for only one pollutant would meet the cutoff for SO_2, not NO_X, and would already be using Appendices D and E. A unit using a fuel flowmeter to determine SO_2 mass emissions under Appendix D likely uses the same fuel flowmeter to determine CO_2 emissions and heat input. Additionally, the same fuel flowmeter is used to determine NO_X emissions under Appendix E. Even if the unit were allowed to use the proposed low mass emissions excepted methodology for SO_2 in lieu of Appendix D, the unit would still have to install, certify, operate, maintain, quality assure, and report from a fuel flowmeter to determine NO_X emission rate and heat input. Accurate heat input is important since heat input is used to calculate NO_X mass emissions. In short, the cost of operation, maintenance, and quality assurance of the fuel flowmeter would not be removed simply by removing the requirement to monitor SO_2. Even if a unit that qualified under the low mass emissions excepted methodology for SO_2 but not for NO_X was currently monitoring with Appendix D, for SO_2 and heat input, and using a NO_X CEM, for NO_X emission rate, using the excepted methodology for SO_2 but not for NO_X would have little benefit since the installation, certification, and quality assurance testing of the fuel flowmeter would still be required to determine heat input. Therefore, today's proposed low mass emissions excepted methodology would be provided as an option only if the unit has low mass emissions of both SO_2 and NO_X. EPA solicits comment on this approach and on whether any benefit of allowing the excepted methodology for one pollutant only would outweigh the added complexity in the excepted methodology.

EPA also considered whether a tonnage cutoff for CO_2 emissions was appropriate as part of the proposed applicability criteria for low mass emissions units. However, the proposed excepted methodology under § 75.19 would require the use of a standard emission factor (in lb of NO_X/mmBtu) for NO_X to determine eligibility for the exception. This would effectively establish an upper limit on the annual heat input for a given fuel and boiler type at the level that would allow the unit to meet the tonnage cutoff applicability requirements. Because CO_2 emissions are directly proportional to heat input, there would be a built-in annual CO_2 emissions cutoff inherent in the methodology.

4. Continuing Applicability Criteria

In drafting today's proposal, EPA also considered how to ensure that after individual units initially qualified to use the reduced monitoring exception, they could continue to use the exception only if they continued to have *de minimis* emissions. Many of the units that would qualify as low mass emissions units under the proposal have low emissions either because they use pipeline natural gas and/or because they operate infrequently. In both of these situations, it is conceivable that a unit's emissions could become significant if the unit's fuel or hours of operation were to change. Most gas-fired units are capable of burning oil, but generally do so only when pipeline natural gas is not available. However, if the prices of gas and oil were to change such that oil became far more economical than gas, some gas-fired units might switch to burning high sulfur oil. Similarly, increases in demand for electricity could cause some peaking units to operate more frequently, thereby generating more emissions. Therefore, EPA is proposing that in order to ensure that emissions from units using the reduced requirements would remain *de minimis*, units would have to continue to meet the applicability criteria in order to qualify as low mass emissions units. Because of the conservative heat input and in some cases, conservative emission factors, the Agency believes that meeting the applicability criteria of less than 25 tons of both SO_2 and NO_X when calculating the emissions using the low mass emissions excepted methodology, will ensure that the actual emissions of the low mass emission units will be below those levels. Therefore, once the methodology is implemented, the on-going applicability would only require that the limits be met with the calculated mass emissions, i.e., the facilities would be required to continue to meet the 25-ton cutoffs on an annual basis, as determined using the emission calculation procedures in proposed § 75.19.

It would, therefore, be necessary for low mass emissions units to report NO_X mass emissions, in addition to the required SO_2 mass emissions and NO_X emission rate, in order to determine continuing applicability. A continuing applicability provision of this nature would prevent a unit from continuing to use the reduced requirements when its emissions were no longer negligible. If a unit initially met the applicability criteria but failed to meet one or both of the annual 25-ton cutoffs in a future year, the unit would become disqualified from using the exception. Sufficient time would be necessary to purchase, install, and certify CEMS or the equipment necessary for monitoring under Appendices D and/or E. Therefore, a unit would not be disqualified until two calendar quarters after the quarter in which the 25-ton cutoff is exceeded and would not be required to certify and report from

monitoring systems until then. If that unit changes, or is projected to change, its fuel or amount of operation in the future so that it would again meet the 25-ton SO_2 and NO_X cutoffs, the unit could again qualify as a low mass emissions unit. However, if the unit initially qualified based on projected operating hours and fuel usage and then was disqualified the unit could not use projected data to qualify again. The unit would need to monitor using CEMS, an approved alternative monitoring system, or an optional protocol under Appendices D and/or E, where applicable, for at least an additional three years in order to accumulate three years of actual data.

5. Reduced Monitoring and Quality Assurance Requirements

As discussed above, today's proposed rule would allow facilities to use a maximum rated hourly heat input value and an emission rate factor to determine the mass emissions from a low-emitting unit for each hour of actual operation. This approach would involve no actual emissions monitoring and no quality assurance activities. Instead, the facility would only need to keep track of whether the unit combusted any fuel for a particular hour and what type of fuel was combusted. In this way, the proposed revisions would significantly reduce the burden on affected facilities, while still ensuring that emissions are not underreported.

6. Reduced Reporting Requirements

Some utilities have mentioned that they find it troublesome to spend as much time or more reviewing quarterly report submissions for small, infrequently operating gas-fired units as they spend reviewing quarterly report submissions for large coal-fired units (see Docket A–97–35, Items II–D–75, II–E–25). EPA agrees that facility environmental personnel should be able to spend a greater percentage of their time focusing on units with higher emissions than on low mass emissions units, which, as discussed above, account for such a small portion of total emissions. Thus, today's proposed rule would simplify the reporting requirements for low-emitting units so that facilities could spend less of their environmental department resources on units with negligible emissions. For units that rely on the procedures in proposed § 75.19(c), the owner or operator would have no requirements related to records or reports of certification testing and would be exempt from all of the specific recordkeeping requirements in §§ 75.54(b) through (e) or 75.57(b) through (e) relating to operating parameter and emissions records. Instead, the rule would require only that an initial certification application, containing data supporting the applicability demonstration, and a monitoring plan be submitted and that limited hourly, quarterly, and year-to-date cumulative data be reported on a quarterly basis. The hourly record would only be reported for hours of unit operation, and an hour in which the unit combusted fuel for any portion of the hour would be considered a full hour, for simplicity.

One utility has suggested that it would be less burdensome if it could simply report its quarterly cumulative emissions, without reporting any supporting hourly data; other utility representatives have indicated that it would be no more burdensome to report an hourly default emission value if the utility were already reporting hourly operating information (see Docket A–97–35, Item II–E–25). For purposes of modeling air quality, the Agency considers hourly operating information far more valuable (e.g., for modeling discrete periods of ozone exceedance) than just a quarterly emission value with no time or date mentioned. Furthermore, because facilities already keep track of the operation of their units for business purposes, keeping track of and reporting hourly operating information should not be a substantial burden. According to industry representatives, however, allowing facilities to record and report default emission values instead of hourly measured values would significantly speed up their review of quarterly reports prior to submission to the Agency (see Docket A–97–35, Item II–E–25). Thus, requiring facilities to report hourly operational data and the default emissions data for the fuel burned that hour, but not hourly measured emissions or heat input in additional record types, would preserve the Agency's ability to model air quality while imposing far less burden upon facilities than the current part 75 requirements. Furthermore, because hourly default values would be employed, the need for missing data procedures would be eliminated and the Data Acquisition and Handling System (DAHS) could be greatly simplified. In fact, the reporting requirements for a low mass emissions unit could most likely be fulfilled with the use of a commercially available spreadsheet software package. EPA has incorporated this approach into today's proposed rule.

D. Quality Assurance Requirements for Moisture Monitoring Systems

Background

Section 75.11(b) of the original January 11, 1993 Acid Rain rule requires the owner or operator to continuously (or on an hourly basis) account for the moisture content of the stack gas when SO_2 concentration is measured on a dry basis. The moisture content is needed to correct the measured hourly stack gas volumetric flow rates to a dry basis when calculating SO_2 mass emission rates in lb/hr. Section 75.13(a) of the rule, as amended on May 17, 1995, contains provisions for CO_2 monitoring paralleling the provisions of § 75.11(b); that is, when CO_2 concentration is measured on a dry basis, a correction for stack gas moisture content is needed to accurately determine the CO_2 mass emissions. The stack gas moisture content is also needed when a dry-basis O_2 monitor is used to account for CO_2 emissions and, in some instances, when accounting for unit heat input (see §§ 75.13(c), 75.16(e), and Equations F–14b, F–16, F–17 and F–18 in Appendix F) or when determining NO_X emission rate in lb/mmBtu (see section 3.2 in Appendix F, and Equations 19–3 through 19–5, 19–8, and 19–9 in Method 19 of Appendix A to part 60).

As presently codified, part 75 does not specify any quality assurance requirements for moisture measurement devices. Implementation has shown this to be an unfortunate omission in the rule, since approximately 5 to 10 percent of the continuous emission monitors in the Acid Rain Program require moisture corrections to accurately measure SO_2, CO_2, or NO_X emissions or heat input (see Docket A–97–35, Item II–I–6). The accuracy of the stack gas moisture measurements directly affects the accuracy of the reported SO_2 mass emission rates, CO_2 mass emission rates, NO_X emission rates and heat input values. An error of 1.0 percent H_2O in measured moisture content causes a 1.0 percent error in the reported emission rate or heat input value. Failure to quality assure the moisture data can therefore result in significant under-reporting of SO_2, CO_2, and NO_X emissions and heat input. The Agency does not know the extent of inaccuracy that currently exists in the measurement of moisture by affected units but believes it is important to require certification and quality assurance of moisture monitors—just as is required for other CEMS used under part 75—because the success of the SO_2 trading system depends on accurate monitoring.

Discussion of Proposed Changes

Today's proposal would incorporate into part 75 quality assurance requirements for moisture monitoring systems. Section 75.11(b) would be revised to require the owner or operator to install, maintain, operate, and *quality assure* a moisture monitoring system. Proposed § 75.11(b) also specifies that a moisture monitoring system may either consist of: (1) a continuous moisture sensor; (2) an oxygen analyzer (or analyzers) capable of measuring O_2 on both a wet basis and on a dry basis; or (3) a system consisting of a temperature sensor and a certified DAHS component capable of determining moisture from a lookup table, i.e., a psychrometric chart (this third option would apply only to saturated gas streams following wet scrubbers). Corresponding changes would be made to §§ 75.12, 75.13(c) and 75.16(e) to require that a quality assured moisture monitoring system be used whenever moisture corrections are needed to accurately account for NO_X emissions, CO_2 emissions, or heat input.

Requirements for the initial certification of moisture monitoring systems are proposed in three new sections, §§ 75.20(c)(5), (c)(6), and (c)(7). To make room for the new sections, existing § 75.20(c)(3) would be deleted; existing §§ 75.20(c)(4) and (c)(5) would be redesignated as §§ 75.20(c)(3) and (c)(4); and existing §§ 75.20(c)(6), (c)(7), and (c)(8) would be redesignated, respectively, as §§ 75.20(c)(8), (c)(9), and (c)(10). The certification requirements for continuous moisture sensors are found in proposed § 75.20(c)(6) and include a 7-day calibration error test and a relative accuracy test audit (RATA). For moisture monitoring systems consisting of one or more wet- and dry-basis oxygen analyzers, the proposed certification requirements are found in § 75.20(c)(5) and include a 7-day calibration error test, a linearity test and a cycle time test of each O_2 analyzer, and a RATA of the moisture measurement system. Corresponding revisions to § 75.22(a)(4) are proposed, specifying that EPA Method 4 (either the standard procedure or the midget impinger procedure) would be used as the reference method for the moisture RATAs. For saturated gas streams, if a lookup table is used to determine the hourly stack gas moisture content, the certification requirement in proposed § 75.20(c)(7) would consist of a DAHS verification. At a minimum, the DAHS verification would have to demonstrate, at three temperatures covering the normal range of stack temperatures, that the software extracts the proper moisture value from the lookup table and applies it correctly to the emission calculations. In today's proposal, a new § 75.4(i) would also be added, requiring owners or operators to complete all of the applicable moisture monitoring system certification tests specified in proposed §§ 75.20(c)(5), (c)(6), and (c)(7) no later than January 1, 2000.

Proposed performance specifications for moisture monitoring systems are found in sections 3.1, 3.2, 3.3, and 3.5 of Appendix A to part 75. These specifications would apply to continuous moisture sensors and to wet- and dry-basis oxygen analyzers. The proposed calibration error specification in section 3.1 for continuous moisture sensors is 3.0 percent of span. A new section, 2.1.5, would be added to Appendix A, defining the span of a moisture sensor as equal to the full-scale range of the instrument and requiring that the range be consistent with section 2.1 of Appendix A. For moisture monitoring systems consisting of wet- and dry-basis O_2 analyzers, the proposed span values and performance specifications for calibration error, linearity, and cycle time in sections 2.1.3, 3.1, 3.2, and 3.5 of Appendix A would be the same as the current specifications for O_2 monitors. The proposed relative accuracy (RA) specification for moisture monitoring systems is found in a new section, 3.3.6, in Appendix A and would be equal to 10.0 percent. An alternative RA specification would also be provided in section 3.3.6, i.e., the relative accuracy would also be acceptable if the difference between the mean difference of the reference method measurements and the moisture monitoring system measurements is within ± 1.0 percent H_2O. A relative accuracy specification of 10.0 percent is being proposed in order to maintain consistency with the relative accuracy requirements for the other program monitors (SO_2, NO_X, flow rate, and CO_2). The Agency notes that moisture RATAs have not previously been required by any other EPA continuous monitoring regulation, and therefore there is no relative accuracy database upon which to draw. However, moisture data are sometimes collected using EPA Method 4 during each run of a part 75 gas monitor RATA to convert the gas reference method readings from a dry basis to a wet basis. Therefore, some part 75 sources that currently account for moisture using wet- and dry-basis oxygen analyzers or a moisture sensor should be able to construct moisture RATAs from previous test data by comparing the Method 4 moisture data from the gas monitor RATAs against the readings recorded by the moisture sensor or O_2 analyzers at the time of the gas RATAs. EPA encourages those facilities that currently make moisture corrections in their emission equations to perform this type of data analysis, if possible, and to provide comment on the appropriateness of the proposed moisture relative accuracy specification.

On-going QA requirements for moisture monitoring systems are also proposed in sections 2.1.1, 2.1.4, 2.2.1, 2.3.1.1, and 2.3.1.2 of Appendix B to part 75. Proposed section 2.1.1 of Appendix B would require daily calibrations of moisture monitoring systems. Continuous moisture sensors would be calibrated in accordance with the manufacturers' recommended procedures. Proposed section 2.1.4 would give control limits for the daily calibrations (i.e., ± 1.0 percent O_2 for oxygen analyzers and ± 6.0 percent of span for continuous moisture sensors). Proposed section 2.2.1 would require quarterly linearity checks of wet- and dry-basis oxygen analyzer(s). Proposed section 2.3.1.1 would require semiannual RATAs of moisture monitoring systems, and proposed section 2.3.1.2 would specify that if a moisture monitoring system achieves a relative accuracy of ≤ 7.5 percent or if the mean difference between the CEMS and reference method values is within ± 0.7 percent H_2O, the system qualifies for an annual, rather than semiannual RATA frequency.

Missing data procedures for moisture are included in today's proposal in a new section, § 75.37. The proposed missing moisture data procedures are as follows:

(1) Begin by using the following ''initial'' missing data procedures as of the date and time of provisional certification of the moisture monitoring system or as of January 1, 2000 (whichever is earlier). Substitute 0.0 percent moisture for each hour of missing data if no prior quality assured data exist, and for the first 720 hours of quality assured monitor operating data, substitute, for each hour of each missing data period, the average of the ''hour before'' and ''hour after'' moisture values.

(2) After 720 hours of quality assured data have been obtained, provided that the moisture data availability is ≥ 90.0 percent, substitute the average of the ''hour before'' and ''hour after'' values for each hour of the missing data period.

(3) When the percent data availability for moisture is below 90.0 percent, substitute 0.0 percent moisture for each hour of the missing data period.

These proposed missing data procedures are considerably simpler than the corresponding procedures for SO_2, NO_X, CO_2, and flow rate, in that they do not include the concepts of lookback periods, 90th, or 95th percentile values. However, the procedures are also somewhat less representative than the missing data procedures for SO_2, NO_X, CO_2, and flow rate, because the most conservative possible value (0.0 percent moisture) is substituted when the moisture monitor data availability drops below 90.0 percent. The Agency solicits comment on whether the simpler (but less accurate) missing data procedures or the more complex (but more representative) procedures are more appropriate.

Finally, §§ 75.57(c) and 75.59(a) (revised versions of §§ 75.54(c) and 75.56(a)) would be added in today's proposal to require that records be kept of the following: (1) Component-system identification code for the moisture monitoring system; (2) hourly average moisture readings (including, if applicable, hourly averages from each wet- and dry-basis O_2 analyzer); (3) percent data availability for the moisture monitoring system; (4) daily and 7-day calibrations of moisture monitoring systems; (5) linearity tests of each wet and dry oxygen analyzer used to determine moisture; and (6) relative accuracy tests of moisture monitoring systems.

In summary, EPA is proposing quality assurance (QA) procedures for moisture monitoring systems because the Agency believes that continuous, quality assured, direct measurement of the stack gas moisture content or continuous measurement of surrogate parameters, such as wet- and dry-basis oxygen concentrations, is the best way to ensure the accuracy of the reported emission data when moisture corrections must be applied. However, the Agency is willing to consider and solicits comment on simpler alternative methods of accounting for the stack gas moisture content, such as using a conservative default moisture value. Any proposed alternative methodology submitted to the Agency for consideration would have to provide a comparable level of accuracy and would have to ensure that emissions and heat input are not under-reported.

E. Certification/Recertification Procedural Changes

Background

Currently, § 75.20 lays out the process for certifying monitoring systems. Section 75.20(a) specifies the requirements for initial certification, including the contents of a certification application, when the application must be submitted and the process for reviewing and acting on an application. Sections 75.20(a)(3) and (4) of the existing rule establish a certification application review period of 120 days (after receipt of a complete application) for EPA to review an application and issue an approval or disapproval. For a continuous emission monitor (CEM), initial certification includes the following tests: relative accuracy, bias, linearity (pollutant monitors only), 7-day calibration error, cycle response time (pollutant monitors only), missing data, and formula verification. All of these tests must be passed for a CEM to be certified and produce valid quality assured data. Once a CEMS is certified, § 75.20(b) specifies that if something changes that significantly affects the ability of the CEM to accurately measure concentration or volumetric flow, the affected monitoring system(s) must be recertified. Recertification includes one or more of the initial certification tests. All required recertification tests must be passed, and a recertification application must be submitted in order for a CEM to be recertified. Section 75.20(b)(5) of the existing rule establishes a 60 day review period for recertification applications. Separate but similar certification and recertification test requirements apply for a monitoring system other than a CEM, i.e., an excepted monitoring system under Appendix D or E, an alternative monitoring system under subpart E, or a system under proposed Appendix I.

Submittal requirements for certification and recertification applications are included in §§ 75.60 and 75.63 of the current part 75. Generally, these provisions require submittal of certification test results in electronic formats, with some information required to be submitted in hardcopy format. Certification or recertification test results also must be submitted electronically in quarterly reports under § 75.64. Finally, § 75.61 requires the designated representative to provide advance notice to the applicable state or local agency and EPA Regional Office of certification and recertification testing.

In many respects, monitoring plan requirements are tied to the certification/recertification process because a modification to the monitoring system that requires a recertification application also usually requires a monitoring plan update. In addition, because it contains the information about what type of equipment is located where, the monitoring plan is an essential tool in the review of a certification or recertification application. Section 75.53 specifies the content of monitoring plans and when changes to the plan are required. Section 75.62(a) specifies the submission requirements for monitoring plans.

Based on EPA's initial experience with part 75 implementation and the numerous questions and problems encountered in the review of certification and recertification applications and monitoring plans, the Agency believes that the certification and recertification provisions and the related sections of the rule are possibly neither sufficiently detailed nor clear. Therefore, in today's rulemaking, EPA is proposing to revise those provisions and sections in order to improve the certification/recertification process. The issues addressed in today's proposed rule include the following: (1) whether a particular provision applies to initial certification, recertification, or both; (2) the scope of events that require submittal of a recertification application; (3) the review period lengths for initial certification and recertification applications; (4) the criteria governing disapproval of an incomplete certification or recertification application; (5) the format (electronic or hardcopy) in which test notifications, certification and recertification applications, and monitoring plans are to be submitted; (6) which EPA Regional Offices and state and local agency offices must receive test notifications, certification and recertification applications, and monitoring plans, and whether the submittal and notice requirements can be waived; and (7) when a monitoring plan needs to be revised. The proposed revisions on these topics and the rationale for the changes are discussed below.

The Agency notes that today's package of proposed revisions to part 75 includes other substantive revisions to the certification and recertification provisions in part 75. These are discussed elsewhere in this preamble. The provisions of most significance are related to certain proposed QA/QC revisions, back-up monitoring systems, CEM data validation issues, and the new Appendix I procedures. See sections III.D, O, R and T of this preamble for further discussion.

Discussion of Proposed Changes

The proposed revisions discussed in this section affect § 75.20 generally, as well as specific aspects of §§ 75.20(a)(4), (b)(1), (b)(5), and (g)(6); 75.21(e)(1); 75.53(b); new § 75.53(e) and (f); 75.60(b); 75.61(a); 75.62(a); 75.63(a) and

(b); 75.64(a), (b) and (d) and the addition of § 75.59 as a revised version of § 75.56. Proposed revisions to § 75.20 would clarify which provisions apply to initial certification, recertification, or both. Proposed revisions to § 75.20(b)(1) and (g)(6) would provide a narrow definition of recertification events, thereby significantly reducing the number of monitoring system changes, configuration changes or changes in the manner of operation that would require submission of a recertification application. Proposed revisions to § 75.20(b)(5) would make the lengths of the review periods the same for initial certification and recertification applications. Proposed revisions to § 75.20(a)(4) would clarify what constitutes a complete certification or recertification application and also would more clearly define EPA's authority to disapprove an incomplete application.

Proposed revisions to § 75.53(b) would expand the universe of monitoring system changes that require monitoring plan revisions to include any change that would make the information in the current plan inaccurate (currently, only changes that require recertification require monitoring plan changes). Sections 75.53(e) and (f), which are revised versions of existing § 75.53(c) and (d), would clarify which elements of a monitoring plan must be submitted in electronic format and which elements must be submitted in hardcopy format. Section 75.53(e) would revise existing § 75.53(c) so that after January 1, 2000 an owner or operator would have to report the unit stack height in the monitoring plan. Section 75.59 (a revised version of § 75.56) would specify the minimum required content (as of January 1, 2000) for the hardcopy portion of a certification or recertification application. Section 75.60(b) would more clearly define the general requirements for submittal of reports and petitions. Section 75.61(a) would allow for certification and recertification test notices to be sent in various alternative media and would allow for EPA or a State or local agency to waive test notices in some circumstances. Section 75.62(a) would be revised to clarify when monitoring plans are to be submitted and to whom elements of the monitoring plan must be submitted. Similarly, § 75.63(a) would be revised to detail which elements of a certification or recertification application are to be submitted electronically, which elements are to be submitted in hard copy, and to whom the various elements would be submitted. Section 75.63(b) would clarify when and how failed tests are to be reported in a certification or recertification application. Finally, § 75.64(a) would specify that the hardcopy monitoring plan is not to be submitted with a quarterly report. The rationale for these changes is discussed below.

Rationale

1. Initial Certification Versus Recertification

Several provisions in the current rule refer either to certifications or to certification applications; however, it is not always clear whether these provisions apply solely to initial certifications or whether they also apply to recertifications. Therefore, today's proposed revisions would make a number of minor text edits throughout § 75.20 for clarification. There are, however, some events that do not fit neatly under the definition of initial certification or recertification (e.g., construction of a new stack with a new CEM at an existing unit when a scrubber is installed). This element of subjectivity in classifying an event as a certification or recertification makes it desirable for the certification and recertification processes to be as similar as possible. Having one general process with one set of rules rather than having two separate processes also makes program implementation easier. Currently, the main differences between initial certifications and recertifications are the types of tests required and the lengths of the application review periods. Today's proposed rule revisions would attempt to minimize these differences to the extent possible in order to bring greater uniformity and consistency to the certification and recertification process.

(a) *Scope of Recertification Events.* The proposed revisions would narrow the scope of the types of changes to a monitoring system that would be classified as ''recertification events'' and would require submittal of a recertification application. Sections 75.20(b)(1) and (g)(6) would define a recertification event as any change that requires the performance of an accuracy test of a monitoring system, i.e., either a relative accuracy test audit (RATA) of a CEMS, an accuracy test of a fuel flowmeter, or a retest to develop the Appendix E NO_X correlation curve. For changes to a monitoring system or process that do not require a system accuracy test but require one or more of the other (lesser) quality assurance tests to be performed (e.g., linearity test or 7-day calibration error test), those other required tests would be classified as diagnostic tests rather than as recertification tests in § 75.20(b)(1) of the proposal. For instance, a source would be required to conduct a linearity check after replacing a capillary tube in a gas analyzer with a tube from a like model and manufacturer (see Docket A–97–35, Item II–I–9, Policy Manual, Question 13.13). However, because this change to the CEMS does not require a RATA, it would not be considered a recertification event. Therefore, no recertification application would be required, and the linearity test would be considered a diagnostic test. Note that even though diagnostic tests would not be classified as recertifications, the recertification data validation procedures in proposed § 75.20(b)(3) of today's rule would apply to these tests. EPA believes that the proposed narrowing of the definition of a recertification event will significantly reduce the number of required recertification applications and will make the submittal requirements for initial certifications and recertifications more consistent.

(b) *Recertification Review Period.* Consistent with the proposed narrowing of the definition of a recertification event, EPA also proposes to revise § 75.20(b)(5) by increasing the recertification application review period from 60 days to 120 days to make it the same as the review period for initial certifications. The advantage of making the two review periods consistent is that there would be no need to distinguish which requirements are applicable to which events. Some events combine aspects of initial certification and of recertification. For example, the certification of a new CEMS on a new stack at an existing unit when a scrubber is installed can be thought of as initial certification because it is an entirely new system in a new location; however, this event also involves aspects of recertification because it is an existing unit which has been reporting emissions from certified systems. Therefore, the Agency believes that making the review periods the same would reduce confusion and case-by-case determination of how long the review period should be for a given application. The Agency believes that it would be more effective to establish consistent procedural requirements for both initial certification and recertification events, rather than attempting to classify each event as an initial certification or recertification.

In making the review periods consistent, EPA considered reducing the length of the review period for initial certifications. EPA considered both the

time it takes to complete a thorough technical review of an application and the time it takes to resolve issues raised during that technical review. The resolution of issues raised during a review can take a significant amount of time because it involves coordination between the source submitting the application, the applicable state and/or local air agency, the applicable EPA Regional Office, and the Acid Rain Division at EPA headquarters. Therefore, even though EPA would anticipate receiving fewer recertification applications under today's proposed revisions, EPA believes that a 120-day review period is necessary for recertifications (which, according to today's proposed definition of a recertification event, would involve the review of monitoring system accuracy tests) in order to coordinate resolution of issues raised during the technical review of an application.

EPA recognizes that there are concerns with increasing the recertification review period to longer than 60 days, as more hours of data could be invalidated if an application were disapproved. However, EPA believes that the criteria for approval of monitoring system certification tests are clear and that when an application is submitted, the owner/operator should know whether or not the performance specifications of part 75 have been met. In EPA's experience of four years of implementation, disapprovals are rarely issued; in fact, less than 2 percent of all monitoring system applications submitted between 1993 and September 1997 were disapproved (see Docket A–97–35, Item II–A–4). In most cases where applications have been disapproved, the owner or operator should have been aware of the deficiencies before the application was submitted. Additionally, EPA has found that a longer review period has allowed more time to resolve minor deficiencies which could have served as grounds for disapproval, but which, given sufficient time, were often resolved without issuing a notice of disapproval and without invalidating any hourly emissions data.

2. Disapproval of an Incomplete Application

Section 75.20(a)(4) of the existing rule requires EPA to issue a ''notice of approval or disapproval of the certification application within 120 days of receipt of the complete certification application.'' This provision implies that an application must be complete in order to issue a disapproval. In attempting to implement this provision, EPA has encountered the problem of incomplete applications. The Agency has, in most of these instances, issued a notice of incompleteness to the source. However, affected sources have not always complied with the incomplete notices and have sometimes failed to submit the information requested to complete the application in a timely manner. Therefore, EPA proposes to clarify that EPA may disapprove an incomplete certification or recertification application if the submittal deadline is passed. Before a disapproval would be issued for an incomplete application, the designated representative would receive a notice of insufficiency and be given a reasonable period of time to complete the application. If the complete application was not received by this extended deadline, EPA could issue a notice of monitoring system disapproval. The Agency believes that this provision will result in faster resolution of incomplete certification or recertification applications, thereby eliminating extended periods of uncertainty about data validation status.

3. Submittal Requirements for Certification and Recertification Applications

The current rule requires the owner or operator to submit certification and recertification applications to the Administrator (i.e., the Acid Rain Division of EPA) and to the appropriate EPA Regional Office and state or local air agency. Hardcopy test results must be submitted, as well as an updated monitoring plan and electronic test results. The electronic test results must also be submitted to the Administrator as part of the next quarterly report.

Sections 75.20(a)(4)(ii), 75.59, and 75.63 of today's proposal would revise and clarify the completeness, format, and submittal requirements for certification and recertification applications. For a certification or recertification application to be considered complete, the appropriate information specified in proposed § 75.63 would be sent to the Administrator, to the EPA Regional Office, and to the state and local air agency. Under proposed § 75.63, the Administrator would receive only a hardcopy application form and would not receive any hardcopy test results, unless specifically requested. The Administrator would, however, receive certification and recertification test results electronically in the quarterly report. In most cases, the electronic test results would be submitted in the quarter in which the testing is completed. However, there may be occasional exceptions to this, for initial certification testing and for recertification testing, when a series of tests spans two consecutive calendar quarters.

The local and State agencies, as well as the EPA Regional Office would receive a hardcopy application form, electronic test results, and hardcopy test results. For recertification tests, today's proposal would allow the EPA Regional Office or the state or local air agency to waive the requirement for a hardcopy recertification test report for their respective offices. The EPA Regional Office or the state or local agency could also reinstate that requirement at a later date. EPA Regional Offices and state and local agencies have historically received hardcopy certification and recertification reports with varying contents and formats. Section 75.59(a)(10) would specify the minimum content for hardcopy certification and recertification reports for gas and stack flow CEMS. Section 75.63(a)(2)(iii) would limit the amount of reporting for ''non-recertification events'' that require diagnostic tests. For a diagnostic test, the only reporting requirement would be to submit the applicable electronic test results in the next quarterly report. For DAHS verifications, no reporting would be required; instead, records of the tests would be maintained on-site in a manner suitable for inspection.

This series of revisions is intended both to clarify the elements of a complete application, and to clarify how and to whom the essential information should be submitted. By not requiring hardcopy test reports to be sent to the Administrator and by allowing the EPA Regional Office or state or local agencies to waive hardcopy recertification test reports, the Agency believes that unnecessary hardcopy reporting to offices that do not intend to review the reports will be eliminated.

Finally, § 75.63(b) would clarify that for failed certification or recertification tests, only tests that affect data validation would need to be reported. For example, if the ordinary rules of data validation, rather than the retrospective validation procedures, were applied and a test failure occurred during the initial certification testing for a new unit, only the passed test would be reported if the test was subsequently repeated and passed. However, if the conditional data validation procedures set forth in § 75.20(b)(3) of today's proposal had been utilized during that same initial certification, the failed test would have to be reported because it would affect the data validation of hourly emissions.

4. Decertification Applicability

The proposed revisions to § 75.21(e)(1) would clarify that excepted monitoring systems under Appendix D, E, or I or an alternative monitoring system under subpart E may be decertified in accordance with § 75.21(e)(1). The proposed revisions would also clarify that decertification would apply to both an initial certification and a recertification. EPA believes that logic and consistency dictate the need for these changes.

5. Recertification Test Notice

Section 75.61(a) would be revised to reduce the burdens associated with submitting notices of recertification tests. The proposed revisions would allow EPA or the state agency to waive notification requirements for recertification tests. Currently, a designated representative must notify EPA and the state agency prior to commencing certification or recertification testing so that EPA or a state representative has an opportunity to observe the testing. Allowing the recertification notification requirement to be waived and providing more media options for notifications will help conserve paper, reduce the reporting burden, and provide more flexibility to facilities when scheduling tests. In addition, the Agency solicits comment on whether § 75.61 should be revised to state that the requirement for written notification could be satisfied by mail, facsimile, or e-mail, subject to approval by the agency receiving the notification.

6. Monitoring Plans

In §§ 75.53(e) and (f), which are revised versions of § 75.53(c) and (d), and § 75.62, today's proposal clarifies completeness and formatting requirements for monitoring plans. In § 75.53(e), the existing provisions would be separated into two separate paragraphs (e)(1) and (e)(2) to clarify which parts of the monitoring plan must be submitted in electronic format and which elements must be submitted in hardcopy format. In addition, a number of minor changes would be made to clarify the actual required content of the plan. Similarly, in § 75.53(f), the same type of revisions would be made to clarify the electronic versus hardcopy elements of monitoring plans for specific situations (Appendix D, E, and I units, units claiming an opacity exemption, and units with add-on emission controls). These proposed revisions are generally consistent with existing implementation of the monitoring plan reporting requirements and primarily would serve to clarify possibly ambiguous elements of the current rule. The revisions reflected in § 75.53(e) would add a requirement to electronically report in the monitoring plan the unit stack height above ground level and the stack base elevation above sea level. EPA understands that these data are readily available to unit owners and operators. EPA collects stack heights for some units, e.g., for new or modified sources subject to 40 CFR § 51.166. However, stack height data is not currently collected for all of the units affected under title IV of the Act. Moreover, the stack height data that the Agency has is inconsistent, i.e., some of the data are for stack height above sea level, some are for above ground level, and some are undefined. Stack height data is necessary to improve the modeling of plume height and transport of sulfates and nitrates as part of acidic deposition and other atmospheric modeling. EPA conducts atmospheric modeling as part of the congressionally-mandated program of air pollution monitoring, analysis, modeling, and inventory research under section 103 of the Act. Such modeling is also used to analyze the impact of the Act on the public health, economy, and environment, pursuant to section 312 of the Act. (See also, e.g., *Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments* at 3–6 through 3–11 (EPA, 1995)). EPA is also proposing to collect the Energy Information Administration (EIA) flue identification numbers associated with each unit. While this data is already reported to EIA, it is difficult to correlate it with the unit and stack level data reported to EPA. By having sources specify for each unit and stack the corresponding flue identification number reported to EIA, it will be easier to correlate the emissions data reported to EPA to other data that is reported to EIA and is used for atmospheric modeling purposes, such as stack exit temperature and velocity.

Section 75.62 would be revised to clarify which parts of the monitoring plan must be submitted to the EPA Regional Office and state and local agencies, and when such submittals are required. The Administrator would receive an electronic monitoring plan at the following times: (1) no later than 45 days prior to the initial certification application; (2) at the time of a recertification application, if a change in the hardcopy monitoring plan information is associated with the recertification event; and (3) in each electronic quarterly report. The EPA Regional Office and state and local agency would receive the required hardcopy monitoring plan 45 days prior to an initial certification. Thereafter, hardcopy monitoring plan information (changed portions, only) would be submitted as follows: (1) with a recertification application, if a change in the hardcopy monitoring plan information is associated with the recertification event; and (2) within 30 days of any other event with which a hardcopy monitoring plan change is associated. Finally, today's proposed rule would require a complete monitoring plan to be kept on-site in a form suitable for inspection (this could include an electronic portion which could be printed out for inspection). These revisions are intended to clarify the monitoring plan format and submission requirements, but are generally consistent with existing practices.

Today's proposal would also clarify when revisions must be made to the monitoring plan. Currently, only changes that require recertification require monitoring plan revisions. The EPA recognizes, however, that many changes affecting the information in a monitoring plan would not require recertification. Therefore, § 75.53(b) would be revised to require that the owner or operator update a monitoring plan whenever information in the monitoring plan changes (e.g., a change to a serial number for a component of a monitoring system), and § 75.62 would require submission of the revised monitoring plan in the next quarterly report or, for hardcopy portions, within 30 days of the change. This revision would assure that the monitoring plan does not contain outdated, erroneous information.

Section 75.64(a) would clarify that no hardcopy monitoring plan is to be submitted with a quarterly report.

7. Submittal Requirements for Petitions and Other Correspondence

Section 75.60(b)(5) would clarify what hardcopy information is sent to the Administrator for petitions and other communications. These revisions would clarify the existing rule, but would not represent a significant change in the requirements for these types of submittals.

F. Substitute Data

1. Missing Data Procedures for CO_2 and Heat Input

Background

In the May 17, 1995 rule, two new sections, §§ 75.35 and 75.36, were added to part 75. These two new sections provided, respectively, missing data procedures for CO_2 and heat input,

which were not provided in the original January 11, 1993 rule. Section 75.35 specifies that for CO_2, the initial missing data procedures of § 75.31 are to be followed for the first 720 quality assured monitor operating hours following initial certification. Thereafter, provided that the CO_2 data availability (as of the last hour of the previous quarter) is maintained above 90.0 percent and provided that the length of any CO_2 missing data period does not exceed 72 consecutive hours, a simple average of the ''hour before'' and ''hour after'' CO_2 concentrations is used to fill in missing data periods. However, if the monitor availability as of the last hour in the previous quarter is below 90.0 percent or if a CO_2 missing data period exceeds 72 consecutive hours in length (regardless of the percent monitor availability), then the fuel sampling procedures of Appendix G must be used to provide substitute CO_2 data.

Section 75.36 has a parallel structure to § 75.35. For units that determine unit heat input by using a flow monitor and a diluent (CO_2 or O_2) monitor, the initial missing data procedures of § 75.31 are to be followed for the first 720 quality assured monitor operating hours (for the diluent monitor) and for the first 2,160 quality assured monitor operating hours (for the flow monitor), following initial certification. Thereafter, the standard missing data procedures of § 75.33 are to be followed for the flow monitor. For the diluent monitor, the on-going missing data provisions of § 75.36 are nearly identical to those for CO_2 in § 75.35 (i.e., use an ''hour before hour after'' missing data algorithm, provided that the monitor availability is ≥ 90.0 percent and the missing data period length is ≤ 72 hours). However, when the diluent monitor availability is < 90.0 percent or when the diluent missing data period exceeds 72 hours, § 75.36 specifies that the owner or operator must use the procedures in section 5.5 of Appendix F to determine the hourly heat input.

Utility representatives have asked EPA to consider revising the missing data procedures for CO_2 and heat input (see, e.g., Docket A–97–35, Items II–D–20, II–D–30, II–E–13, and II–E–14). The utilities object to several elements of the current procedures. They suggest that the Appendix G procedures are burdensome and that the missing data procedures are considerably different from the standard missing data procedures for SO_2, NO_X, and flow rate, which are based solely on historical data and monitor availability and require no additional procedures such as fuel sampling.

Discussion of Proposed Changes

EPA has reconsidered the provisions of §§ 75.35 and 75.36 in light of the concerns raised by the regulated community, and is proposing revisions to the diluent gas missing data procedures for CO_2 and for heat input determinations. The Agency proposes that the same missing data routines prescribed in § 75.33(b) for SO_2 pollutant concentration monitors also be applied to the CO_2 and O_2 data streams that are used to determine CO_2 emissions and heat input. The diluent gas substitute data values would therefore be determined in a purely mathematical way, based on historical data and the percent monitor data availability; no fuel sampling procedures would be required.

Note that these proposed revisions would require the percent monitor data availability to be known on an hourly basis. This would require the percent availability for CO_2 and O_2 monitors to be updated hourly within the data acquisition system. EPA realizes that this would involve software modifications, and in cases where the unit heat input is determined using a flow monitor and an O_2 diluent monitor in accordance with Equation F–17 or F–18, some new recordkeeping provisions would also be required. The necessary recordkeeping provisions have been proposed in § 75.57(g). To allow time for software revisions to be made, the revised missing data procedures in §§ 75.35 and 75.36 would not take effect until January 1, 2000. The owner or operator could, however, opt to use the new procedures prior to January 1, 2000.

EPA believes that today's proposed revisions to the missing data procedures for CO_2 and heat input determinations would be relatively easy to implement because the missing data routines for SO_2 monitors are well-established and are familiar to both the regulated community and to software vendors. The Agency believes that the proposed revised missing data procedures would ensure that data availability remains high and would, over time, reduce the cost of compliance with the requirements of part 75.

2. Prohibition Against Low Monitor Data Availability

Background

Under the current rule, when a unit uses SO_2, flow rate, and NO_X monitoring systems to account for its emissions, for each clock hour in which a CEMS fails to provide quality assured data, a substitute data value must be reported to EPA in accordance with the standard missing data procedures of § 75.33. The method required for determining the appropriate substitute data values under § 75.33 depends on several factors, such as the overall monitor data availability and the length of the missing data period. For monitor data availabilities ≥ 90.0 percent, the substitute data value (which is reported for each clock hour of the missing data period) will normally be the arithmetic average of the readings from the hour before and the hour after the missing data period. At other times, it will be the 90th (or 95th) percentile value from a lookback period of 720 (for SO_2) or 2,160 (for NO_X and flow rate) quality assured monitor operating hours. When the data availability drops below 90.0 percent, the substitute data value for SO_2 will be the maximum concentration recorded in the last 720 quality assured monitor operating hours, and for flow rate and NO_X, the substitute data value will be the maximum flow rate or NO_X emission rate recorded in the last 2,160 quality assured monitor operating hours at the corresponding load range.

Based on four years of program implementation, EPA believes that the standard missing data procedures need to be strengthened. As presently written, the missing data algorithms lack a safeguard which will ensure that high monitor data availability continues to be maintained in future years. In the current version of § 75.33, no distinction is made between data availabilities of 89.0 percent, 50.0 percent or 10.0 percent. For all three of these data availability percentages, the substitute data value is the same (i.e., the maximum value in a lookback period of 720 or 2,160 quality-assured monitor operating hours). This has potentially serious consequences. For example, if the substitute data value from the lookback period is non-punitive or perhaps is even favorable to the facility (e.g., if a low-sulfur fuel was burned during the lookback period), there would be little incentive to repair a malfunctioning CEMS in a timely manner and emissions could possibly be under-reported for a long period of time. Currently, part 75 does not specifically address this ''gaming activity.''

Discussion of Proposed Changes

In order to maintain the credibility of the SO_2 allowance accounting system and to ensure that affected units continue to comply with their part 76 NO_X emission limits, monitor data availability must not be allowed to deteriorate indefinitely without clear and significant consequence to the facility. Therefore, in today's rulemaking, EPA is proposing to add a

safeguard to part 75 to ensure that this does not happen. A new paragraph 75.33(d) would be added, which would make it a violation of the primary measurement requirement of § 75.10(a) to allow the annual monitor data availability to drop below 80.0 percent for SO_2, NO_X, flow rate, or CO_2. Based on an analysis conducted on data availability information for the third quarter of 1996, EPA believes that affected facilities will easily be able to comply with the 80.0 percent data availability criterion (see analyses in Docket A–97–35, Item II–B–16). The results of that analysis indicated a mean percent monitor data availability of 96.9 percent for SO_2, 95.0 percent for NO_X, and 96.6 percent for flow rate. Although there were 13 (out of 995 total) SO_2 monitors, 21 (out of 997 total) flow monitors, and 46 (out of 1365 total) NO_X monitoring systems with percent monitor availabilities below 80.0 percent in the 4th quarter of 1996, the Agency expects that many of these systems would be exempt from the prohibition based on a limited number of operating hours in the previous year (see Docket A–97–35, Item II–A–8).

The proposed prohibition would not apply to units that have only a limited number of operating hours (less than 3000 hours of operation in the previous 12 calendar quarters) because such units can have a low data availability percentage without necessarily having extended monitor downtime incidents. In addition, no violation would occur if the low monitor availability is caused by a sudden and reasonably unforeseeable event beyond the control of the owner or operator (such as destruction of monitoring equipment by fire or flood). The owner or operator would, however, be required to notify the Administrator, in writing, within 7 days of the occurrence of such catastrophic events and also to provide notification to the EPA Regional Office and to the appropriate State agency. The owner or operator would be further required to submit a corrective action plan, including an implementation schedule. Thus, this proposed prohibition should not result in violations of part 75, except for situations involving poor operation and maintenance practices, which are clearly *not* beyond the control of the owner or operator.

Another option considered by the Agency was to modify the standard missing data algorithms for SO_2, NO_X, and flow rate as follows. Under this option, the algorithms for monitor data availabilities of 90.0 percent to 100.0 percent would remain unchanged. The algorithms currently used for *all* monitor data availabilities below 90.0 percent would be retained, but these would apply only to data availabilities between 80.0 percent and 89.9 percent. Finally, a new algorithm would be added for monitor data availabilities below 80.0 percent. When the data availability drops below 80.0 percent, the appropriate *maximum* substitute data value would have to be used (i.e., the maximum potential concentration for SO_2 or CO_2, the maximum NO_X emission rate, or the maximum potential flow rate). EPA believes that requiring maximum values to be reported when the data availability drops below 80.0 percent would provide incentive to the affected sources to keep their monitors well-maintained. Because any changes to the standard missing data algorithms would require software modifications, this option, if adopted, would not take effect until January 1, 2000. The Agency has not proposed this option because it would require software changes for all affected units even though very few units have data availabilities that fall below 80.0 percent. The Agency seeks comment, however, on whether this option should be used instead of the proposed prohibition given that it is more consistent with the structure of the missing data requirements in part 75 and would be self-implementing without any need to initiate enforcement actions to achieve the desired result of continued high data availabilities that assure accurate reporting of emissions.

The Agency also emphasizes that the required data availability for the Acid Rain Program would remain at 100.0 percent even if the proposed prohibition is adopted, meaning that substitute data would have to be supplied for any periods in which data from a certified monitoring system are not available. This approach is in sharp contrast to most other CEMS programs that do not rely on substitute data. In those programs, the Agency, as well as State and local agencies, expect and often require much higher data availabilities than 80.0 percent. Based on the number of units with data availability higher than 95.0 percent under the Acid Rain Program, CEMS data availability less than 95.0 percent may well indicate a failure to properly operate and maintain a CEMS. Many agencies rely on that 95.0 percent availability level to target systems for inspection and other compliance-related follow-up actions. In addition, agencies have adopted various required minimum data availabilities for CEMS that far exceed the 80.0 percent level selected for the prohibition proposed in today's rulemaking.

It is also important to note that monitor availability under part 75 and monitor downtime under other programs are not always the same. Under part 75, a source may have actual monitoring data that are suspect, based on an evaluation of various quality assurance activities. In this situation, the owner or operator may, as a conservative measure, report substitute data rather than the actual data. In contrast, this type of missing data substitution does not occur under most other programs. In most programs, the suspect data would simply be invalidated and no emission data would be reported for those hours.

Therefore, because of the structure of the missing data provisions in the Acid Rain Program and the generally applicable economic incentive to achieve high data availabilities under part 75, it would be improper to equate the proposed prohibition in today's rulemaking with a required minimum data availability requirement established for other programs that do not have the same features. The Agency does not intend that this proposed provision should serve as a precedent for evaluating the appropriate achievable data availability for other programs. Consistent with current practices, the Agency would continue to expect CEMS to achieve high data availability and that, generally, monitor downtime in excess of 5.0 percent may warrant appropriate investigation and follow-up activities.

G. General Authority to Grant Petitions Under Part 75

Background

Section 75.66(a) provides generally that a designated representative of a unit subject to part 75 may submit a petition to the Administrator. Sections 75.66(b) through (h) address petitions to the Administrator on the specified topics of alternative flow monitoring methods, alternatives to standards incorporated by reference, alternative monitoring systems, parametric monitoring procedures, missing data for units with add-on emission controls, emission or heat input apportionments, and the partial recertification process. Each of these subsections set forth the items which must be included with a particular type of petition. In addition, § 75.66(i) states that, for any other petition to the Administrator under part 75, the designated representative for an affected unit shall include sufficient information for the evaluation of such petition.

Discussion of Proposed Changes

Today's proposal would revise § 75.66(a) to state clearly that the designated representative of an affected unit may petition the Administrator for authorization to apply an alternative to any requirement under part 75 or incorporated by reference in part 75, regardless of whether another section of part 75 explicitly allows such a petition concerning the particular requirement. EPA views this change as a clarification to the general authority already provided by §§ 75.66(a) and (i). The proposed rule would also be amended to include new paragraphs (i) through (l), which would set forth the specific requirements for other petitions that are explicitly allowed by other sections of the rule but which are not currently included in this section. In addition, the proposed rule, at § 75.66(m), would also indicate the appropriate documentation to be submitted for petitions under subsection (a), except those under subsections (b) through (l), where the required documentation is already specified. The required documentation in subsection (m) would be: (1) Identification of the unit; (2) information explaining why the proposed alternative should be used instead of the existing part 75 provision; (3) descriptions and, if applicable, diagrams of the equipment and procedures to be used in the proposed alternative; and (4) information demonstrating that the proposed alternative is consistent with the purposes of the provision for which an alternative is requested and is consistent with the purposes of part 75 and of section 412 of the Act.

Rationale

As presently codified, EPA is concerned that the rule does not state clearly what types of petitions may be submitted under § 75.66. In particular, existing subsection (i) could be interpreted as referring only to petitions that are mentioned in other sections of part 75 and that are not specifically listed in § 75.66(b) through (h). EPA has not interpreted § 75.66(i) in this manner. In administering the Act, EPA has inherent discretion to grant *de minimis* exceptions from statutory or regulatory requirements, where EPA determines that holding the regulated entity to the applicable requirement would yield a gain of trivial or no benefit, provided Congress has not unambiguously demonstrated its intent to foreclose such exceptions. *See, e.g., Public Citizen* v. *Young*, 831 F.2d 1108, 113 (D.C. Cir. 1987); *Alabama Power Co.* v. *Costle*, 636 F.2d 323, 360–61 (D.C. Cir. 1979). Since the issuance of part 75 in 1993, EPA has accepted, and, in some cases exercised its discretion and granted, petitions under § 75.66 that requested exceptions and that were not specifically referenced in § 75.66(b) through (h) or elsewhere in part 75 (see Docket A–97–35, Item II–B–17). Such petitions have included, for example, a request to set a CO_2 span lower than that required by part 75 in order to more accurately quality assure the CO_2 monitor. Another petition requested an alternative to the requirement to perform an annual RATA on a unit that was scheduled to shutdown, prior to the deadline for performing the RATA, in order to install a scrubber, construct a new stack, and install and certify new CEMS. A petition was also submitted for permission to use a propane sampling frequency as specified in the State operating permit and to then calculate SO_2 emissions by using the highest sulfur content recorded during the previous 365 days and report these data in quarterly reports. These petitions were submitted for the purpose of requesting alternatives to various requirements of part 75, even though the ability to petition the Agency on these issues was not referenced explicitly in other sections of part 75 or in § 75.66(b) through (h). In most cases, the circumstances leading to the request for an alternative to a part 75 requirement were not anticipated during the drafting of part 75 regulations. In fact, today's proposal revises several part 75 requirements to allow for alternatives that were originally requested and approved through the petition process set forth in § 75.66. The Agency continues to believe that the general provision allowing petitions for alternatives to part 75 requirements is necessary to enable EPA to address circumstances that were not foreseen during the development of such requirements. This is important since circumstances can sometimes vary significantly from boiler to boiler. While the response to comment document for the January 11, 1993 rule (see Docket A–91–69, Item V–C–1, Issue # M–8.8.2) might be read to bar petitions for exceptions from any provision of part 75, EPA maintains that such a reading would be inconsistent with the regulatory language of §§ 75.66(a) and (i) that allow such petitions, and with the established practice of the Agency in administering part 75.

The existing § 75.66(i) states that for petitions other than § 75.66(b) through (h) petitions submitted under the section, the designated representative should include sufficient information for the evaluation of the petition. No other information is provided concerning the contents of such petitions. As §§ 75.66(b) through (h) all provide a list of the type of information that should be included in petitions submitted under the respective sections, the Agency believes that, in addition to amending § 75.66(a) to clarify that petitions may be submitted for circumstances that may not be covered by other sections authorizing petitions to the Administrator, it is appropriate to provide units with a list of the type of information that should be included with the petition. Similarly, EPA believes that it is appropriate to add to the section provisions setting forth the information requirements for those petitions that are explicitly allowed under other sections of part 75 but that are not listed in the existing § 75.66. All these revisions would make the petition process more uniform and minimize confusion regarding what information EPA would require in order to accept and consider any petition for an alternative to a part 75 requirement.

H. NO_X Mass Monitoring Provisions for Adoption by NO_X Mass Reduction Programs

Background

Part 75 contains requirements for monitoring NO_X emissions with a continuous emission monitoring system or other approved method. Owners and operators are required to calculate hourly, quarterly average, and annual average NO_X emission rates (in lb/mmBtu). Part 75, however, currently contains no requirements for reporting NO_X mass emissions (in tons). Other NO_X emission reduction programs being developed pursuant to title I of the Act (such as the NO_X Budget Program in the Ozone Transport Region) are expected to require reporting of NO_X mass emissions from many of the units affected under the Acid Rain Program. To streamline reporting burdens under multiple programs and to allow for the administration of multi-state NO_X mass trading programs, the Agency believes it appropriate to amend part 75 to include provisions for monitoring, recording, and reporting NO_X mass emissions that could apply to such trading programs. These provisions would provide standard procedures—resulting in precise, reliable, accessible, and timely emissions data—that could be adopted under a state or federal NO_X mass emission reduction program. To the extent that these standard provisions are adopted, the burden on industry would be reduced and the administration of the programs would be facilitated, in

that the Agency or implementing states would not need to develop NO_X mass monitoring provisions anew and industry would not need to become familiar with multiple approaches to NO_X mass monitoring.

Discussion of Proposed Changes

The proposed NO_X mass emissions provisions would apply only where EPA, states, or groups of states incorporate them and mandate their use through a separate regulatory action. The proposed amendments would make changes to §§ 75.1, 75.2, 75.4, 75.16, 75.17, Appendix D, section 2.1.2.2, and Appendix F, section 5.5. They would also add a new subpart H containing new §§ 75.70, through 75.73 and a new section 8 in Appendix F containing sections 8.1, 8.1.1, 8.1.2, 8.1.3, 8.1.4, 8.2, 8.3, 8.3.1, and 8.3.2.

Section 75.1, the purpose and scope section, would be amended to broaden the scope by adding that part 75 will also set forth provisions for monitoring and reporting NO_X mass emissions that EPA, states, or groups of states may require sources to use to demonstrate compliance with a NO_X mass emission reduction program. Section 75.2 would be amended to add that the provisions of part 75 may also apply to sources subject to a state or federal NO_X mass emission reduction program.

The compliance date section, § 75.4(a), would be altered to state that the provisions relating to monitoring and reporting of NO_X mass emissions become applicable on the deadlines specified in the applicable state or federal NO_X mass emission reduction program requiring the use of part 75 to monitor and report NO_X mass emissions.

Section 75.16 would be amended to state that title IV affected units using the provisions of part 75 to monitor and report NO_X mass emissions under a state or federal NO_X mass emission reduction program would have to meet the heat input monitoring and determination requirements in both § 75.16 and in subpart H, §§ 75.71 and 75.72. Section 75.17 would be amended to state that title IV affected units using the provisions of part 75 to monitor and report NO_X mass emissions under such a program would have to meet the NO_X emission monitoring and determination requirements in both § 75.17 and subpart H, §§ 75.71 and 75.72.

The applicable procedures for the monitoring and determination of NO_X mass emissions would be added in proposed subpart H, §§ 75.70, 75.71, and 75.72 and corresponding recordkeeping and reporting requirements would be set forth in § 75.73.

Section 75.70 would set forth the general requirements including: definitions, compliance dates, incorporation by reference, initial certification and recertification procedures, quality assurance and quality control requirements, substitute data requirements, and requirements regarding petitions. In general these provisions for monitoring NO_X mass would mirror the provisions for monitoring of SO_2, NO_X, and CO_2 for compliance with title IV. However, because the program would be a state program, rather than a federal program, there would be some differences in the administrative requirements. These differences would be most pronounced for units that were not subject to Acid Rain emission limitations and were not already subject to the provisions of part 75. The major differences in administrative requirements would involve the process for petitioning under § 75.66 and the process for certifying and recertifying monitors. Under the existing Acid Rain Program, the Administrator must approve all petitions under § 75.66. Under this proposal, petitions for units that were only subject to the provisions of part 75 because they were subject to a state or federal NO_X mass emission reduction program, would have to be approved by both the permitting authority for the applicable NO_X mass program and the Administrator. The permitting authority would also be responsible for reviewing and approving or disapproving certification and recertification applications for such units.

Section 75.71 sets forth the general monitoring methodologies that would be allowed for different types of units. The proposal would require units to determine hourly NO_X mass emissions (in lb) by monitoring NO_X emission rate (in lbs/mmBtu) and heat input (in mmBtu/hr) on an hourly basis and by multiplying those two values and the hourly unit operating time (in hour or fraction of an hour) together. Coal units and other units that burn solid fuel and that are covered by subpart H would be required to measure NO_X emission rate using a NO_X emission rate CEM consisting of a NO_X concentration CEM and a diluent CEM (CO_2 or O_2 CEM) and to measure heat input using a diluent CEM and a continuous volumetric flow monitor. All gas- and oil-fired units covered by subpart H would be allowed to use that approach or, alternatively, could measure NO_X emission rate using a NO_X emission rate CEM and heat input by using a fuel flowmeter and performing fuel sampling and analysis. This alternative for determining heat input from gas- and oil-fired units is set forth in Appendix D of part 75. Gas and oil units that qualify as either peaking units or low mass emission units under part 75 would also have additional lower cost monitoring methodologies available to them. Peaking units, for example, would have the option to do source testing to create heat input versus NO_X emission rate correlation curves. Then, based on hourly measurement of heat input from a fuel flowmeter and fuel sampling and analysis using the provisions in Appendix D to part 75, the heat input vs NO_X emission rate correlation curves would be used to estimate the hourly NO_X emission rate. This rate would be used in conjunction with hourly measured heat input to determine NO_X mass. A unit that qualifies as a low mass emission unit would have the option to use a fuel-type and boiler-type specific default NO_X emission rate and the unit's maximum rated hourly heat input to determine NO_X mass emissions. The low mass emissions unit provisions are in proposed § 75.19.

Section 75.72 sets forth the specific requirements for monitoring emissions at units that share common stacks and/or common pipes, for units that emit to multiple stacks and for units that receive fuel from multiple pipes. These provisions mirror similar provisions in § 75.16 for monitoring SO_2 mass emissions from similar units and groups of units.

Appendix D, section 2.1.2.2 would indicate that the heat input apportionment procedures of that section would not be applicable for units whose compliance with this part is required under a NO_X mass emissions reduction program. Instead, the unit would have to meet the heat input monitoring and determination requirements in subpart H, §§ 75.71 and 75.72.

The applicable procedures for calculating NO_X mass emissions would be added in proposed section 8 of Appendix F. Section 8.1 of Appendix F contains proposed equations for determining hourly NO_X mass emissions, section 8.2 contains proposed equations for determining quarterly, cumulative annual and ozone season NO_X mass emissions, and section 8.3 contains specific provisions for monitoring NO_X emissions from a common stack. Additionally, revisions to section 5.5 of Appendix F would indicate that the heat input calculation procedures of section 5.5.3 would not be applicable for units whose compliance with this part is required under a NO_X mass emissions reduction program.

Rationale

(a) *Authority to Propose NO_X Mass Provisions.* The authority for the proposed NO_X mass provisions rests in two separate portions of the Act. First, section 412(a) states that the owner or operator of an affected source under title IV must monitor and quality assure data for sulfur dioxide and nitrogen oxide for each affected unit at the source. 42 U.S.C. 7651k(a). This section does not limit the nitrogen oxide data requirement to emission rate data in lb/mmBtu or to data necessary for compliance with emission limits established under title IV. Indeed, oil- and gas-fired units have been required to report NO_X emission rate data under part 75 even though only existing coal units are subject to NO_X emission limits under title IV. (*See* 58 FR 3590, 3644, January 11, 1993). Thus, the Agency believes that providing for reporting NO_X mass emissions under part 75 is an appropriate exercise of the authority under section 412, particularly since NO_X mass emissions reporting may be required under a separate applicable requirement.

Second, independently of the authority granted by section 412, section 114(a) of the Act gives the Administrator broad authority to collect data for ''the purpose of developing or assisting in the development of any implementation plan under section 110 or 111(d)'', ''of determining whether any person is in violation of any such standard or a requirement of such a plan'', or ''carrying out any other provision of [the] Act'' (except certain provisions of title II concerning mobile sources). Section 114 is, of course, not limited to sources that are affected units under title IV. Moreover, section 301(a)(1) authorizes the Administrator ''to prescribe such regulations as are necessary to carry out his functions'' under the Act, including the functions specified in section 114. Thus, EPA maintains that the Agency is authorized to adopt provisions in part 75 that could govern monitoring of NO_X mass emissions, especially where such information is expected to support States' efforts to attain ambient air quality standards.

From a policy perspective, now is the appropriate and most efficient time to adopt these changes. In July 1997, EPA Administrator Carol Browner announced a series of initiatives to reform environmental data management and collection (see Docket A–97–35, Item II–I–21). The new initiatives are intended to streamline reporting requirements and increase coordination across different programs that affect the same sources. There are a number of examples of ongoing efforts to streamline the reporting of emissions for utility units. One example is a proposal to revise the NSPS NO_X standards for utility and industrial boilers subject to reporting under 40 CFR part 60. That proposal would allow facilities to submit NSPS reports through part 75 reporting (see 62 FR 36948, July 9, 1997). Another example is the Ozone Transport Commission's NO_X Budget program. That program is expected to require utility sources and certain industrial sources in the northeast to reduce emissions of NO_X through a trading program similar to the Acid Rain SO_2 trading program. On January 31, 1996, the OTC released the Model Rule which outlines procedures for the monitoring and reporting of NO_X mass emissions; these procedures are based on the monitoring and reporting requirements set forth in part 75 (see Docket A–97–35, Items II–I–7 and II–I–22). Today's proposal would facilitate the coordination of reporting under the Acid Rain Program and NO_X mass programs like the OTC NO_X Budget Program.

In addition, the Agency believes it is appropriate to include these requirements in the current proposal because the Acid Rain affected units may be undertaking DAHS software changes to respond to the other proposed revisions to part 75 if they are adopted. The Agency would enable facilities to coordinate the necessary software changes by proposing the revised reporting requirements to allow for NO_X mass emission reporting at this time along with the other part 75 revisions. Although EPA is proposing this requirement now to facilitate software changes, the requirement to actually record and report NO_X mass emission data under part 75 generally would not become effective for any unit unless and until a program requiring such recording and reporting is implemented for that particular unit (EPA notes that, as discussed elsewhere in Section III.C.4. of this preamble, a limited group of title IV affected units (i.e., low mass emissions units) would be required to record and report NO_X mass emissions for purposes of the Acid Rain Program.) In addition, if a state elected to require the use of these requirements to support a state NO_X mass emission monitoring and reporting requirement, these requirements would not become federally enforceable until those requirements were approved by EPA as part of the SIP.

(b) *Monitoring Methodology.* The proposed requirement would require sources to determine NO_X mass as a function of hourly average NO_X emission rates, heat input rates, and unit operating time. EPA is proposing this approach because it accurately accounts for NO_X mass emissions without requiring any changes to the current missing data routines and quality assurance requirements in part 75. An alternative to this approach, not included in today's proposal, would be to measure total mass emissions using a NO_X pollutant concentration monitor, a volumetric flow monitor and unit operating time, analogous to the approach taken currently for SO_2 emissions. This methodology would have two advantages: first, there would be less missing data from a NO_X pollutant concentration monitor than from a NO_X CEMS which (under the existing and proposed rule) contains both a NO_X pollutant concentration monitor and a diluent monitor; and second, it would avoid possible overestimation from a bias adjustment factor applied to the NO_X system to correct bias in the diluent monitor (see Docket A–97–35, Item II–D–96).

However, this methodology would also have a number of disadvantages. In order to monitor NO_X as total mass emissions using a NO_X pollutant concentration monitor and a volumetric flow monitor, several major changes would need to be made to part 75. The entire concept of a NO_X CEMS—and the quality assurance tests and missing data procedures associated with the NO_X CEMS—might need to be revised, to include either a NO_X CEMS with only a NO_X pollutant concentration monitor and a DAHS (in which case, a separate flow monitoring system would also be required in order to determine NO_X mass), or a NO_X CEMS with a NO_X pollutant concentration monitor, a volumetric flow monitor, and a DAHS. Since the relative accuracy standard currently in part 75 for NO_X systems is in lb/mmBtu, it would be necessary to establish a new relative accuracy standard for NO_X concentration in ppm if the NO_X/flow method described above were incorporated into the final rule. Bias adjustment would also have to occur on the newly defined NO_X CEMS. It would also be necessary to create a missing data procedure either for NO_X concentration in ppm or for hourly NO_X mass emission rate in lb/hr. Hourly NO_X mass emission rate would be calculated using the same formula as for SO_2 mass emission rate (Equation F–1 or F–2), only using a constant of 1.194×10^{-7}(lb/scf)/ppm NO_X. In addition, this methodology would not easily support the monitoring and reporting of NO_X emission rate data in lb/mmBtu.

Therefore, in order to meet the emission rate reporting requirements, affected sources under title IV would still be required to maintain a diluent CEMS and the current NO_X emission rate missing data procedures. The Agency has not proposed this approach because it does not believe that the benefits of slightly reduced amounts of missing data for NO_X mass and removal of the bias adjustment factor for the diluent monitor justify the complication of having two separate procedures for monitoring NO_X emissions from a given unit. Nevertheless, the Agency requests comment on whether this approach to measuring mass emissions should be used in lieu of the proposed heat input and emission rate approach for sources required to report NO_X mass.

(c) *Common Stack and Pipe Monitoring.* The Agency notes that the proposed procedures for monitoring NO_X emission rate at a common stack to determine NO_X mass emissions under the proposed § 75.72 procedures are different than the procedures currently allowed for monitoring NO_X emission rate in § 75.17. The Agency is concerned that the § 75.17 provisions would be too imprecise for measuring NO_X mass emissions because the two values used to determine NO_X mass emissions (NO_X emission rate and heat input) are not required to be measured at the same location. In the existing rule, NO_X emission rate may be monitored at the unit level in the duct leading to the common stack and heat input can be determined from measurements at the common stack and then apportioned to the individual units using unit load. While this heat input apportionment method has been allowed for Acid Rain purposes, it is not accurate in all cases because it does not account for different heat rates from the units exhausting to the common stack and does not account for differences in operating time at the units. It has been allowed by the Agency for Acid Rain purposes because apportioned heat input determined under § 75.16 (e) had only a limited effect on emissions trading (i.e., on the SO_2 allowance program). Although apportioned heat input determined under § 75.16(e) is used to determine compliance with the reduced utilization provisions of the Acid Rain Program, the apportioned heat input estimate was deemed accurate enough for that purpose and for the relatively small number of units and short period involved. Determinations of reduced utilization are required only for Phase I units during 1995–1999 and for opt-in units. However, for purposes of a NO_X mass trading program, the heat input value would be used in the calculation to determine NO_X mass, and an imprecise unit level heat input value could cause the NO_X mass emissions from some units to be underestimated. The NO_X mass trading program could be undermined by the lack of a consistent emissions value for each NO_X allowance. Therefore, the proposed provisions for monitoring heat input and NO_X emission rate from units in a NO_X mass trading program would be similar to the provisions that are currently used for monitoring SO_2 mass emissions at a common stack at § 75.16. The provisions for monitoring SO_2 mass emissions require that the two values needed to determine SO_2 mass emissions, stack flow rate and SO_2 concentration, be monitored at the same location. The Agency is proposing that, for purposes of determining NO_X mass emissions, a facility could use the same location options currently available for SO_2: the facility could either monitor both NO_X emission rate and heat input at the common stack level or monitor them both at the unit level. The Agency is also proposing a third option: heat input could be monitored at the unit level and summed to the common stack level, while NO_X emission rate could be monitored at the common stack level. Even though this option would allow NO_X emission rate and heat input to be measured at different locations, it does not have the inherent inaccuracies described above because it does not require heat input apportionment.

Similarly, the optional procedures currently allowed for the apportionment of heat input measured at a common pipe in Appendix D, section 2.1.2.2 are not available for units with a common pipe under subpart H. As discussed above for common stacks, the Agency is concerned that the heat input apportionment under Appendix D, section 2.1.2.2 provisions would be too imprecise for the purpose of calculating NO_X mass emissions. In the existing rule, heat input can be determined from measurements at the common pipe and then apportioned to the individual units using unit load. For purposes of calculating NO_X mass emissions under subpart H for a unit which is supplied fuel from a common pipe, the measurement of fuel flow rate would have to be made at the pipe leading to the individual unit in order to determine unit level heat input.

The Agency solicits comment on the proposed approach for monitoring NO_X mass emissions at a common stack or pipe and whether it is appropriate to mirror the common stack and pipe provisions for SO_2 mass emissions.

(d) *Multiple duct/stack monitoring.* The current provisions for monitoring NO_X emission rate, in §§ 75.17(c)(1) and (2), allow the owner or operator to determine NO_X emission rate for a unit that exhausts through multiple ducts or stacks using a Btu-weighted sum of the NO_X emission rates measured in each duct or stack or by monitoring NO_X emission rate in only one duct or stack. The new proposed § 75.72 would set forth specific requirements for monitoring NO_X mass in multiple ducts or stacks and would in some cases place a number of limits on the options in § 75.17(c) and in some cases not allow the options in § 75.17(c). The proposed options for monitoring NO_X mass are similar to the existing provision in § 75.16(d) for monitoring SO_2 mass emissions at multiple ducts/stacks. They are also similar to the provisions being used in the OTC NO_X Budget Program to determine NO_X mass in similar situations.

The new proposed § 75.72 does not contain an option for any units to use a Btu-weighted sum of the NO_X emission rates measured in each duct or stack. The reason that this option is not appropriate is that in order to use this option to determine a unit's NO_X emission rate, the owner or operator of the unit would have to monitor both NO_X emission rate and heat input in each duct or stack. (As discussed above, the heat input apportionment method allowed under § 75.17 is not sufficiently accurate for a NO_X mass program.) These two values allow the calculation of NO_X mass and, therefore, there is no reason to determine a Btu-weighted sum for purposes of this subpart.

The new proposed § 75.72 would not allow coal units to monitor NO_X emission rate in only one duct or stack. The proposal would also not allow gas and oil units to monitor the NO_X emission rate in only one duct or stack, unless heat input is determined using the provisions of Appendix D to this part and the owner or operator makes a demonstration that the emission rate would always be the same in both ducts or stacks. Reasons that the emission rate might vary include the use of add-on emission controls in the ducts or stacks or venting of emissions to one duct or stack and not the other.

These limitations are required for monitoring mass emissions (in lbs), but are not necessary for monitoring emission rate (in lbs/mmBtu) at coal units or gas and oil units that use continuous volumetric flow monitors, because, for reasons discussed above, monitoring mass requires the monitoring of both emission rate and heat input. Since the amount of stack

flow that is vented to each duct or stack could vary significantly depending upon the location and use of dampers and induction fans in the ducts or stacks, it is necessary to measure volumetric flow in both ducts or stacks in order to determine heat input for the unit(s). In order to accurately use these heat input values to determine NO_X mass, it is also necessary to measure NO_X emission rate in both ducts or stacks. Therefore, proposed § 75.72 would require monitoring of heat input and NO_X emission rate in both ducts or stacks for coal units and gas-and oil-fired units that use continuous volumetric flow monitors and exhaust to multiple ducts or stacks.

Since gas-and oil-fired units that are using the procedures in appendix D of part 75 to determine heat input based on fuel consumption do not have to measure volumetric flow in the duct or stack in order to determine heat input, EPA believes it is appropriate to allow these units to measure NO_X emission rate in only one duct or stack if they can demonstrate to both the permitting authority and the Administrator that the NO_X emission rate in either duct or stack is representative of the NO_X emission rate in each duct or stack. Therefore, proposed § 75.72 allows gas-and oil-fired units that are using the procedures in appendix D of part 75 to measure NO_X emission rate in only one duct or stack if they can demonstrate to both the permitting authority and the Administrator that the NO_X emission rate in either duct or stack is representative of the NO_X emission rate in each duct or stack.

(e) *Reporting of NO_X* Mass Emissions. The Agency also notes that the proposed procedures differ in two key respects from the way data is currently reported under part 75. The first difference is that the proposal would require reporting of hourly NO_X mass emissions, in lbs, (instead of hourly mass emission rate, in lb/hr, as is currently required for the reporting of SO_2 under part 75). The OTC NO_X Budget Program is expected to require the reporting of hourly mass emissions, in lb, rather than hourly mass emission rates, in lb/hr, because of experience under the Acid Rain Program with reporting hourly SO_2 and CO_2 mass emission rates. As discussed in Section III.R.1 of this preamble, the reporting of hourly SO_2 and CO_2 mass emission rates has been a source of some confusion in the implementation of the Acid Rain Program. For the reasons presented in Section III.R.1 of this preamble, EPA is not proposing to change the existing SO_2 and CO_2 reporting requirements. However, the existing part 75 does not require any NO_X mass emission reporting, and in order to avoid the problems experienced under the Acid Rain Program and to be consistent with the OTC NO_X Budget Program, EPA proposes here to base the new NO_X reporting on mass emissions in pounds. Maintaining consistency with the provisions expected to be adopted for the OTC NO_X Budget Program is important to ensure that a central body such as EPA would be able to effectively administer the program if states opted to participate in a multi-state NO_X trading program larger than the Ozone Transport Region covered by the OTC NO_X Budget Program.

The second key difference is that, in addition to reporting a quarterly and cumulative annual total emissions value, the proposed revisions would also require reporting of a cumulative ozone season total value. Generally, the ozone season extends from May 1 to September 30 of every year. The cumulative ozone season emissions would be reported with the second quarter and third quarter reports submitted to EPA. The reason that reporting would be required on an ozone season basis is that one of the main reasons the data is being collected is to support other programs designed to control emissions during the ozone season.

(f) *Role of EPA and States/Localities in Administering the Monitoring Portion of a NO_X* Trading Program. The Agency also notes that another important potential difference between the use of this part to support the Acid Rain Program under Title IV of the CAA and the use of this part to support other NO_X mass emission reduction programs is the role that EPA and the state or local permitting authority that may establish such a program will play. Under the Acid Rain Program, even though many states have assumed the role of the permitting authority under Phase II of the program, EPA still retains authority to issue approvals and disapprovals related to all of the monitoring and reporting issues, such as certification of monitoring systems under § 75.20, approval of petitions under § 75.66 and approvals of alternate monitoring petitions under § 75.48. EPA believes that if a NO_X mass emission reduction program is approved as part of a SIP or if EPA agrees to work with individual or groups of states to help administer the monitoring and reporting portion of a NO_X mass emission reduction program, EPA would still have to be involved in the approval process.

The level of this involvement might vary depending upon the specific type of approval or disapproval. It also would vary depending upon whether or not the unit had an Acid Rain emission limitation. For instance, EPA would play a significant role in the approval of an alternate monitoring petition under § 75.48 or any other petitions under § 75.66. For a unit with an Acid Rain emission limitation, any petition would already have to be approved by EPA. In order to streamline the process for these sources, EPA believes that EPA should continue to issue approvals and disapprovals of petitions. However, since sources would also be using the monitored data to meet SIP requirements, EPA would take this action in consultation with the applicable state. For units that are not subject to an Acid Rain emission limitation, EPA would still need to be involved in petition determinations. There are two primary reasons that this involvement would be necessary. The first would be as part of EPA's typical role in assuring that any alternative to the approved SIP will still result in the air quality benefit that would have been derived if the permitting authority had not deviated from the SIP. The second would be as part of EPA's role in administering the emissions tracking portion of a NO_X mass emission reduction program. If EPA was not involved and a state approved, for a unit, an alternative that allowed variations to the reporting requirements, EPA might not be able to administer the emissions tracking portion of the program for that unit. Similarly, for approval and disapproval of certification applications and recertification applications, EPA believes that there should be two separate requirements; one for units subject to an Acid Rain emission limitation, and one for units not subject to an Acid Rain emission limitation. For units subject to an Acid Rain emission limitation, EPA would still approve or disapprove certification and recertification applications. This would streamline the process for units since they would only have to deal with one regulatory agency for both programs. For units not subject to an Acid Rain emission limitation, the permitting authority would approve certification and recertification applications. EPA requests comment on this approach and whether the respective roles of the Administrator and the permitting authority should be different for units that are subject to both an Acid Rain emission limitation and to a NO_X mass emission reduction program and for units that are subject solely to a NO_X mass emission reduction program.

I. Span and Range Requirements

Background

The span and range requirements for part 75 continuous emission monitoring systems are found under section 2.1 of Appendix A to the January 11, 1993, rule, as amended on May 17, 1995. Sections 2.1.1, 2.1.2, 2.1.3 and 2.1.4 of Appendix A give the specific span and range requirements for SO_2 monitors, NO_X monitors, diluent (O_2 and CO_2) monitors, and flow rate monitors, respectively.

The span of a CEMS provides an estimate of the highest expected value for the parameter being measured by the CEMS. For instance, the span value of an SO_2 monitor should be an approximation, based on the type of fuel being combusted, of the highest SO_2 concentration likely to be recorded by the CEMS during operation of the affected unit. The range of a CEMS is the full-scale setting of the instrument. Under part 75, the range of a monitor must be equal to or greater than the span value. Section 2.1 of Appendix A further specifies that the range must be chosen such that the majority of the readings during normal operation fall between 25.0 and 75.0 percent of full-scale. Part 75 span values are used to determine the appropriate reference gas concentrations and reference signals for daily calibration of the CEMS; the reference concentrations and signal values are expressed as percentages of the span value. The allowable daily calibration error for a CEMS is also expressed as a percentage of span.

Sections 2.1.1 through 2.1.4 of Appendix A to the January 11, 1993 rule specified procedures for determining the span values for four parameters: SO_2, NO_X, diluent gas (O_2 or CO_2), and volumetric flow rate. For SO_2, the ''maximum potential concentration'' (MPC) was first calculated based on fuel sampling results from the previous 12 months (using the highest sulfur content and lowest heating value in Equation A–1a or A–1b). The SO_2 span value was then obtained by multiplying the MPC by 1.25 and rounding the result upward to the next highest multiple of 100.0 ppm. The MPC values for NO_X were specified in the rule and were based on the type of fuel being combusted (e.g., 800.0 ppm for coal-firing and 400.0 ppm for oil-firing). The NO_X span value was then determined by multiplying the MPC by 1.25 (e.g., 1000.0 ppm for coal-firing and 500.0 ppm for oil-firing). For CO_2 and O_2, a span value of 20.0 percent CO_2 or O_2 was required for all diluent monitors. For flow rate, the ''maximum potential velocity'' (MPV) was first determined either using Equation A–3a (or A–3b) or from historical test data (i.e., from velocity traverses conducted at or near maximum load). Then, the span value was obtained by multiplying the MPV by 1.25 and rounding the result upward to the next highest multiple of 100 feet per minute (fpm).

In the January 11, 1993 rule, the SO_2 or NO_X monitor range derived from the MPC was referred to as the ''high-scale.'' The rule further specified that whenever the majority of the readings during normal operation were expected to be less than 25.0 percent of the high full-scale range value (e.g., if a scrubber were used to reduce SO_2 emissions), a second, ''low-scale'' span and range would be required. The low scale of the CEMS would be defined as 1.25 times the ''maximum expected concentration'' (MEC). The original rule was prescriptive regarding the method of determining the MEC. For SO_2, the MEC was to be calculated using Equation A–2; for NO_X, an MEC value of 320.0 ppm was to be used for coal-firing and 160.0 ppm for oil-or gas-firing.

In the first two years of Acid Rain Program implementation, it became increasingly clear to both the regulated community and to EPA that the span and range provisions of part 75 lacked sufficient flexibility and clarity. The NO_X provisions were particularly problematic, being overly prescriptive in some instances and sometimes requiring two spans and ranges when a single, appropriately-sized range would suffice. Also, the units of the flow rate span were expressed in terms of velocity (i.e., feet per minute), and this was not consistent with either the units of measure used for daily monitor calibrations or the units used for electronic reporting of flow rate data.

The May 17, 1995 rule attempted to address these deficiencies, as follows. For SO_2, an alternative means of determining the MPC, in lieu of using historical fuel sampling data, was added; the MPC could be based upon 30 days of historical CEMS data. The use of historical CEMS data was also allowed as an option for MEC determinations, instead of using Equation A-2. For NO_X, the method of determining the MPC was made less prescriptive. First, a comprehensive list of MPC values was promulgated (Tables 2–1 and 2–2 in Appendix A), taking into consideration the unit type in addition to the fuel type. The MPC value from this list could be used in lieu of the fuel-based MPC prescribed in the original rule. Second, two alternative methods of determining the MPC or MEC were added, i.e., from historical CEMS data or from emission test results. Finally, flexibility was added to the dual-range requirements for NO_X monitors so that, in many instances, the span and range requirements of part 75 could be met on a site-specific basis, using a single span and range.

The span provisions for CO_2 and O_2 were not significantly changed in the May 17, 1995 rule. For flow rate, however, a more detailed procedure for determining the span value was added. This addition was considered necessary because during the first year of program implementation it came to light that there are actually two important span values associated with flow rate: (a) the ''calibration'' span value used for daily calibrations, and (b) the ''flow rate'' span value in units of standard cubic feet per hour (scfh). These two span values are both derived from the MPV, but are almost invariably expressed in different units of measure, and, therefore, the two spans are generally not equal numerically. For instance, the calibration span value for the daily calibration of a differential pressure-type flow monitor, expressed in units of inches of water, is a small number (generally less than 5.0 in. H_2O); while the flow rate span value, in scfh, is a very large number, usually in the tens or hundreds of millions.

The May 17, 1995 rule also revised the procedures for adjusting the span and range of SO_2, NO_X, and flow monitors. Sections 2.1.1.4, 2.1.2.4, and 2.1.4 of Appendix A to the original rule had specified that span and range adjustments were required whenever the MPC, the MEC, or the MPV changed significantly. When a significant change in the MPC, MEC, or MPV occurred, a new range setting was to be established and a new span value defined, equal to 80.0 percent of the adjusted range value. The revised sections 2.1.1.4, 2.1.2.4, and 2.1.4 of Appendix A to the May 17, 1995 rule changed this procedure, requiring the new span value to be determined first, followed by the new range. The May 17, 1995 rule also added procedures for addressing full-scale exceedances, specifying that the full-scale value is to be reported for an exceedance of one hour and that a range adjustment is required for an exceedance greater than one hour. Finally, the May 17, 1995 rule specified that whenever the range of a gas monitor is adjusted, a linearity test is required, and a calibration error test must be done when the range of a flow monitor is adjusted.

Discussion of Proposed Changes

Since promulgation of the May 17, 1995 rule, EPA has continued to receive questions and comments about the span and range sections of part 75. Many of

the questions and comments have centered on the adjustment of span and range. The following questions are typical: When must the span and range be changed? What constitutes a ''significant'' change in the MPC, MEC, or MPV? When a span and range adjustment is required, what are the deadlines for making the changes and for completing the required linearity test? How should full-scale exceedances be reported? There also appears to be some lingering confusion and misunderstanding about how to determine the flow rate span values and how to calculate the maximum potential flow rate (MPF) and the NO_X maximum emission rate (MER) (see Docket A–97–35, Items II–B–8, II–D–67, and II–E–31). In view of this, EPA believes that the span and range sections of the rule are still not sufficiently clear, flexible, or detailed and are in need of further revision. In June, 1996, a national part 75 CEM Implementation Workgroup meeting was held in Washington D.C. to discuss possible revisions to part 75. One of the principal topics of discussion was span and range (see Docket A–97–35, Item II–E–32). Today's rulemaking proposes comprehensive revisions to sections 2.1 through 2.1.4 of Appendix A, based in part on the discussions of the June, 1996 meeting. The principal changes are described in paragraphs (1) through (5), below.

1. Maximum Potential Values

The basic procedure for determining the maximum potential of SO_2 concentration would be unchanged by today's proposal. However, two new provisions would be added to section 2.1.1.1 of Appendix A to prevent overestimation of the MPC. The first of these provisions would allow the exclusion of clearly anomalous fuel sampling results when determining the MPC. The second provision would apply to units for which the designated representative certifies that the highest sulfur fuel is never combusted alone, but is always blended or co-fired with other fuel(s) during normal operation. For such units, the MPC would be calculated using best estimates of the highest sulfur content and lowest gross calorific value expected for the blend or fuel mixture and inserting these values into Equation A–1a or A–1b. The best estimates of the highest percent sulfur and lowest GCV for a blend or fuel mixture would be derived from weighted-average values based upon the historical composition of the blend or mixture in the previous 12 (or more) months.

The alternative procedure for determining the MPC of SO_2 based upon quality assured historical CEMS data would be retained, but it is proposed that the MPC be based, at a minimum, upon the previous 720 quality assured monitor operating hours, rather than the previous 30 unit operating days. This is to ensure that a sufficient quantity of valid data is used for the MPC determination. Making the determination based on 30 unit operating days does not provide that assurance, particularly for units that may only operate for a few hours a day (e.g., peaking units). Revised section 2.1.1.1 would also specify that for a unit with add-on SO_2 emission controls, the historical CEMS data option may only be selected if the certified SO_2 monitor used to determine the MPC is located at the control device inlet.

For NO_X, the general procedures for determining the MPC would also remain the same, i.e., either: (1) use the MPC value prescribed in the original rule, (2) use the unit-specific value listed in Table 2–1 or 2–2, or (3) determine the MPC by emission testing or from historical CEM data. However, the following changes to section 2.1.2.1 of Appendix A are proposed. First, a statement would be added that the MPC would have to be based upon the combustion of whichever fuel or blend combusted at the unit produces the highest level of NO_X emissions. Second, an advisory statement would be added, noting that the initial MPC value determined for a unit that is not equipped with low-NO_X burners (LNB) would have to be re-evaluated if a low-NO_X burner system is subsequently installed and optimized. Third, if historical CEMS data are used to determine the MPC, the determination would have to be based on the previous 720 (or more) quality assured monitor operating hours (instead of the previous 30 unit operating days). Fourth, units with add-on NO_X emission controls could only use the historical CEM data option if the historical data represented uncontrolled emissions (e.g., if the certified CEMS used to collect the data were located prior to the control device inlet or, for a unit with seasonal NO_X controls, if the historical data were from a period when the controls were not operating). Fifth, if emission testing is used for the MPC determination, sufficient tests would have to be performed at various loads and excess oxygen levels to ensure that a credible MPC value is obtained. For units with add-on NO_X emission controls, the emission test data would have to be collected upstream of all controls, or, for a unit with seasonal controls, during a period when the controls were not operating. Finally, a specific requirement to calculate the maximum potential NO_X emission rate (MER) would be added to section 2.1.2.1 of Appendix A. The May 17, 1995 rule had provided a definition of the MER in § 72.2; however, a corresponding requirement to calculate the MER was not included in part 75 at that time. The MER is occasionally needed to provide substitute NO_X emission rates during missing data periods. The owner or operator would be permitted to use the diluent cap value of 5.0 percent CO_2 or 14.0 percent O_2 for boilers (or 1.0 percent CO_2 or 19.0 percent O_2 for turbines) in the NO_X MER calculation.

For CO_2, today's proposed rule would add a new section 2.1.3.1 to Appendix A, which provides a definition of the MPC. The MPC for CO_2 pollutant concentration monitors would be 14.0 percent for boilers and 6.0 percent CO_2 for combustion turbines. Alternatively, the MPC could be based on a minimum of 720 hours of representative quality assured historical CEM data.

For flow rate, the procedure for determining the MPV would be essentially unchanged by today's proposed rule, i.e., the MPV would either be determined from Equation A–3a (or A–3b, as applicable) in Appendix A, or it would be based on velocity traverse data taken at or near maximum load. However, a procedure for calculating the maximum potential flow rate (MPF) would be added to section 2.1.4.1 of Appendix A. The MPF is occasionally used to provide substitute flow rate data; therefore, a clear, consistent method of determining the MPF is needed.

2. Maximum Expected SO_2 and NO_X Concentrations

Today's proposal would significantly change the procedures for determining the maximum expected concentration (MEC) of SO_2. The purpose of the revisions would be to ensure that the proper span(s) and range(s) are selected for SO_2 measurement. Proposed section 2.1.1.2 of Appendix A would require the MEC to be determined for units with SO_2 controls and also for uncontrolled units that burn both high- and low-sulfur fuels (or blends) as primary or backup fuels (e.g., high- and low-sulfur coal or different grades of fuel oil).

The revised procedures for determining the MEC for SO_2 would be as follows. For units with emission controls, Equation A–2 in Appendix A would be used to calculate the MEC. For uncontrolled units that burn both high-sulfur and low-sulfur fuels or blends as primary or backup fuels, Equation A–1a or A–1b in Appendix A (which in the

current rule is reserved for MPC calculations) would be used to determine an MEC value for each fuel or blend, with three important exceptions. The MEC would not be calculated for: (1) the highest-sulfur fuel or blend (because it would be duplicative of the MPC calculation); (2) fuels or blends with a total sulfur content no greater than the total sulfur content of natural gas, i.e., ≤ 0.05 percent sulfur by weight, because § 75.11(e)(3)(iv) of the current rule specifies that natural gas combustion does not trigger a dual span and range requirement for the SO_2 monitor (for gas firing, the MEC and low-scale span values would be too low to be practical for quality assurance purposes, e.g., < 5 ppm for pipeline natural gas); and (3) fuels or blends that are combusted only during unit startup, because such fuels are infrequently used and are not representative of normal unit operation.

Today's proposal would continue to allow the same flexibility in the SO_2 MEC determination that was introduced in the May 17, 1995 rule. That is, if a certified SO_2 CEMS is already installed, the owner or operator could determine the MEC based upon historical continuous monitoring data, in lieu of using mathematical equations. If this option were chosen for a unit with SO_2 controls, the MEC would be the maximum SO_2 concentration measured at the control device outlet by the CEMS over the previous 720 or more quality assured monitor operating hours with the unit and the control device both operating normally. For units that burn both high- and low-sulfur fuels or blends as primary and backup fuels and have no SO_2 controls, the MEC for each fuel would be the maximum SO_2 concentration measured by the CEMS over the previous 720 or more quality assured monitor operating hours in which that fuel or blend was the only fuel being burned in the unit.

Today's rule also proposes to change the way in which the MEC is determined for NO_X. Revised section 2.1.2.2 of Appendix A would require a determination of the MEC during normal operation for units with add-on NO_X controls capable of reducing NO_X emissions to 20.0 percent or less of the uncontrolled level (i.e., steam injection, water injection, selective catalytic reduction or selective non-catalytic reduction). A separate MEC determination would be required for each type of fuel combusted, except for fuels that are only used for unit startup or for flame stabilization. The MEC would be determined in one of three ways: (1) using Equation A–2 in Appendix A; or, if that equation is not appropriate, (2) by emission testing or (3) by using historical CEMS data from the previous 720 (or more) quality assured monitor operating hours. Revised section 2.1.2.2 would give specific guidelines and procedures by which to obtain the MEC when the emission testing or CEMS data options are selected. All CEMS or emission test data used for the MEC determination would be taken under stable operating conditions with all control devices and methods operating properly.

3. *Span and Range Values*

For SO_2, NO_X, and flow rate, respectively, revised sections 2.1.1.3, 2.1.2.3 and 2.1.4.2 of Appendix A would allow the high-scale span value to be between 100.0 and 125.0 percent of the maximum potential value (i.e., the MPC or MPV), rounded off appropriately. This is a change from the current rule which requires the high span to be set at 125.0 percent of MPC or MPV, rounded off appropriately. However, the change is not expected to be disruptive, because properly sized span values previously determined by multiplying the MPC or MPV by 1.25 could continue to be used. The change would allow the owner or operator to set the span value in such a way that a small exceedance of MPC or MPV would not require a span change (see paragraph 5, ''Adjustment of Span and Range,'' below). The added flexibility in span selection would also allow different units with similar (but not identical) MPCs for SO_2 and/or NO_X to use the same span value and to use the same calibration gas concentrations, which could result in cost savings for some facilities. In 1996, EPA received and approved a petition from one utility to equalize the SO_2 span values at several of its coal-fired units (see Docket A–97–35, Items II–C–23, II–D–71).

For CO_2 and O_2 monitors, today's proposal would revise section 2.1.3 of Appendix A to allow the owner or operator maximum flexibility in selecting an appropriate span value. The CO_2 or O_2 span value would not be determined in the same way as an SO_2, NO_X, or flow rate span value. Rather, for CO_2 monitors installed on boilers, any convenient span value between 14.0 percent and 20.0 percent CO_2 representing the percent diluent in the flue gas would be acceptable. For combustion turbines, any CO_2 span value between 6.0 and 14.0 percent CO_2 could be used. For O_2 monitors, a span value between 15.0 percent and 25.0 percent O_2 could be selected. However, if the O_2 concentrations are expected to be consistently below 15.0 percent, an alternative span value of less than 15.0 percent could be used, provided that an acceptable technical justification was included in the monitoring plan. The proposed rule would also allow purified instrument air containing 20.9 percent O_2 to be used as the high level calibration gas for oxygen monitors having span values greater than or equal to 21.0 percent O_2.

There are two principal reasons why EPA is proposing increased flexibility in the selection of the CO_2 and O_2 span values. The first is to encourage greater accuracy in the diluent gas measurements. The revisions would allow the span value to be customized so that the concentration of the upscale calibration gas used for daily calibrations can be as close as possible to the actual average CO_2 or O_2 concentrations in the stack. In 1996, EPA received and approved a petition from one utility to use a CO_2 span value of 15.0 percent for its coal-fired units, rather than the 20.0 percent span value required by part 75 (see Docket A–97–35, Items II–C–20, II–D–68). The second reason for revising the CO_2 and O_2 span requirements is to eliminate unnecessary high-level span and range requirements. The current rule requires a high span value of 20.0 percent for all CO_2 and O_2 monitors. However, there are many units (e.g., combustion turbines) for which the diluent gas concentrations are so low that the guideline in the current section 2.1 of Appendix A (i.e., that the majority of the readings be within 25.0 to 75.0 percent of full-scale) cannot be met unless a second, low-scale span and range are used. For most of these units, there are technical and safety reasons why the diluent concentrations must remain low; therefore, it is unreasonable to require a high range to be maintained if a lower range will suffice and can never be exceeded. During the Phase II certification process, EPA approved CO_2 span values of 10.0 percent for a number of combustion turbines and waived the high-scale range requirement (see Docket A–97–35, Items II–C–19, II–C–21, II–D–64).

Today's proposal would not change the basic way in which the full-scale range setting of a monitor is determined. The range would still have to be set greater than or equal to the span value. However, the guideline for selecting an appropriate full-scale range in section 2.1 of Appendix A would be revised as follows. With few exceptions, the full-scale range would be selected so that, to the extent practicable, the readings during typical unit operation fall between 20.0 and 80.0 percent of full-scale; this represents a slight increase in flexibility from the ''25-to-75 percent of

full-scale'' guideline in the current rule. Today's proposal would also emphasize that section 2.1 is only a guideline and would cite three specific cases in which it is inapplicable. Specifically, the guideline would not apply to: (1) quality assured SO_2 readings obtained during the combustion of natural gas or fuel with equivalent total sulfur content (because the resulting SO_2 emissions are too low to be subject to the span and range requirements); (2) quality assured SO_2 or NO_X readings on the high range for an affected unit with SO_2 or NO_X emission controls and two span values (because the high range is not the normal operating range for the unit); and (3) quality assured SO_2 or NO_X readings less than 20.0 percent of the low measurement range for a dual-span unit with SO_2 or NO_X emission controls, provided that the low readings are associated with periods of high control device efficiency (because it is not necessary to re-range a monitor based on non-representative hours of exceptional control performance).

For flow monitors, today's rule proposes to revise section 2.1.4.2 of Appendix A to more clearly define the ''calibration span value'' (which is the span expressed in the units of measure used for the daily calibrations) and the ''flow rate span value'' (which is the span expressed in the units used for electronic data reporting, i.e., scfh). The proposed rule defines these two span values in considerable detail and outlines how to use them. EPA believes that this will result in greater consistency in implementation of the part 75 flow rate monitoring requirements.

4. Dual Span and Range Requirements for SO_2 and NO_X

In today's rule, revisions are proposed to the dual span and range requirements for SO_2 and NO_X monitors in sections 2.1.1.4 and 2.1.2.4 of Appendix A. The revised provisions are essentially the same for both pollutants. To determine whether a second, low-scale span is required in addition to the high-scale span based on the MPC, each of the maximum expected concentration (MEC) values determined under revised section 2.1.1.2 or 2.1.2.2 of Appendix A would be compared against the maximum potential concentration (MPC) determined under proposed sections 2.1.1.1 or 2.1.2.1. If this comparison shows any of the MEC values to be < 20.0 percent of the MPC, a low-scale span would be required. If several of the MEC values are found to be < 20.0 percent of the MPC, then the low-scale span would be based upon whichever MEC value is closest to 20.0 percent of the MPC. The low-scale span value would be determined in a manner similar to the high-scale span, i.e., by multiplying the MEC by a factor between 1.00 and 1.25 and rounding off the result appropriately.

When both a high-scale span and a low-scale span are required for SO_2 or NO_X, proposed sections 2.1.1.4 and 2.1.2.4 would allow the owner or operator to use either of the following monitor configurations to meet the dual-range requirement: (1) a single analyzer with two ranges, or (2) two separate analyzers connected to a common probe and sample interface. The use of other monitoring configurations would be subject to the approval of the Administrator. The monitor configurations would be represented in the monitoring plan as follows: (a) the high and low ranges could be designated as two separate, primary monitoring systems; (b) the high and low ranges could be designated as separate components of a single, primary monitoring system; or (c) one range (the ''normal'' range) could be designated as a primary monitoring system, and the other range as a non-redundant backup monitoring system. The high and low ranges would be quality assured according to their designation in the monitoring plan. Primary monitoring systems would have to meet the QA requirements for primary systems in § 75.20(c), Appendix A, and Appendix B, with the following exception: relative accuracy test audits (RATAs) would be required only on the normal range. For units with emission controls, the low range would be considered normal; for other units, the range in use at the time of the scheduled RATA would be considered normal. Non-redundant backup systems would have to meet the applicable QA requirements for ''like-kind replacement analyzers'' in proposed § 75.20(d).

Today's rule would add a new alternative provision under sections 2.1.1.4 and 2.1.2.4 of Appendix A for dual-span units with SO_2 or NO_X emission controls. The new provision would allow the owner or operator to use a ''default high-range value'' in lieu of operating, maintaining, and quality assuring a high-scale monitor range. The default high-range value would be 200.0 percent of the MPC (based on uncontrolled emissions). This value would be reported whenever the SO_2 or NO_X concentration exceeded the full-scale of the low-range analyzer. The default high-range value is being proposed for controlled units that seldom, if ever, experience full-scale exceedances of the low monitor range during normal operation (e.g., units that have a permit condition requiring cessation of unit operation when a full-scale exceedance occurs or units that experience low-range exceedances only during startup). EPA solicits comment on the proposed approach of using a default high-range value in lieu of a high range monitor and on the value of the default.

EPA specifically requests comment on whether the proposed dual-span monitoring configurations, monitoring system designations, and quality assurance requirements are adequate, or whether there are additional configurations (e.g., one range with two spans, two separate analyzers with separate probes, etc.) that should be included in the rule.

Finally, when two spans and ranges are required, proposed revised sections 2.1.1.4 and 2.1.2.4 of Appendix A would specify that the low range would have to be used to record emission data when the SO_2 or NO_X concentrations are expected to be consistently below 20.0 percent of the MPC (i.e., when a fuel or blend with a MEC value < 20.0 percent of the MPC is combusted). And if the full-scale of the low range is exceeded, the high range would be used to record data (or, if applicable, the default high range value would be reported).

5. *Adjustment of Span and Range*

In today's rule, detailed guidelines and procedures are proposed for adjusting the span and range of the CEMS in revised sections 2.1.1.5, 2.1.2.5, 2.1.3.2 and 2.1.4.3 of Appendix A. The intent of these provisions is to ensure that each owner or operator assesses the adequacy of all CEMS span values on at least a quarterly basis (and whenever operational changes are planned) and, based on that assessment, makes any necessary adjustments to the spans or ranges in a timely manner. EPA believes that the proposed procedures are sufficiently flexible so that frequent span and range adjustments will not be necessary. The procedures are primarily directed at CEMS with improperly-sized spans and ranges, to bring them into full conformance with part 75 requirements or for future changes in unit operation (e.g., fuel switch or low-NO_X burner installation) that may significantly affect the level of emissions or flow. All required span or range adjustments would have to be made no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, unless the span change would require new calibration gases to be ordered for daily calibration error and linearity tests, in which case, the owner or operator would have up to

90 days after the end of the quarter to make the span adjustment.

The revised procedures for span and range adjustment would be as follows. First, if the maximum value upon which the high span value is based (i.e., the MPC or, for flow rate, the MPF) is exceeded during a calendar quarter, but the span is not exceeded, the span or range would not have to be adjusted. However, for missing data purposes, if any quality assured hourly concentration or flow rate exceeds the MPC or MPF by ≥ 5.0 percent during the quarter, a new MPC or MPF would have to be defined, equal to the highest value recorded during the quarter, and a monitoring plan update would be required. Second, for the high measurement range, if any quality assured reading exceeded the span value by ≥ 10.0 percent during the quarter but did not exceed the range, a new MPC or MPF (as applicable) would have to be defined, equal to the highest on-scale reading recorded during the quarter, and the span value would also have to be changed. If the new span value exceeded the current full-scale range setting, then a new range setting would also be required. Similar span adjustment requirements would apply to the low scale if the two measurement ranges are used separately for distinctly different modes of operation (e.g., during the combustion of different fuels), rather than being used in combination to provide a continuum of measurement range capability.

The proposed procedures for responding to full-scale exceedances are as follows. Whenever the full-scale of a high monitor range is exceeded, excluding hours of non-representative operating conditions (e.g., a trial burn of a new fuel), corrective action would be required to adjust the span and range. In addition, any time the range is exceeded, a value of 200.0 percent of the current full-scale range would be reported to EPA for each hour of each full-scale exceedance. The Agency believes that 200.0 percent of the range is sufficiently conservative to ensure that emissions would not be under-reported. One utility that experienced a full-scale exceedance of the high SO_2 monitor range estimated from the results of fuel sampling that the SO_2 concentration was approximately 150.0 percent of full-scale during the incident (see Docket A–97–35, Item II–D–24).

For units with two span values and two measurement ranges for a particular parameter (e.g., SO_2), when the full-scale of the low range is exceeded, provided that the high monitor range is available to record emission data, no corrective actions would be required. However, if, at the time of the low-range exceedance or during the continuation of the low-range exceedance, the high range is either out-of-service or out-of-control for any reason (and therefore is not available to record quality assured data), the MPC would have to be reported until the readings either returned to the low scale or until the high scale returned to service and was able to provide quality assured data. However, if the reason the high scale is unavailable is because of a high scale exceedance, 200.0 percent of the high range value would be reported for each hour of the exceedance.

Proposed sections 2.1.1.5(e), 2.1.2.5(e), and 2.1.4.3(e) of Appendix A would require that the monitoring plan be updated whenever changes are made in the maximum potential values, maximum expected values, span values, or full-scale range settings. The updates would be made in the quarter in which the changes become effective. The proposed sections 2.1.1.5(e) and 2.1.2.5(e) of Appendix A would further require a linearity test to be done whenever the span of a gas monitor is adjusted, if the span change is significant enough to require new calibration gases for daily calibration error tests and linearity checks. Finally, proposed sections 2.1.4.3(c) and (d) of Appendix A would require a calibration error test to be done whenever a flow monitor span or range is adjusted (unless the adjustment requires a significant change to the flow monitor that would require recertification under § 75.20(b)).

J. Quality Assurance/Quality Control (QA/QC) Program

1. QA/QC Plan

Background

Section 1 of Appendix B to part 75 as originally promulgated on January 11, 1993 sets forth provisions for developing and implementing a quality control program. As part of the quality control program, section 1 requires that the source develop and maintain a quality control plan that documents how the equipment used to report emissions data for part 75 is maintained and quality assured. While the provisions in sections 1.1, 1.2, and 1.4 of Appendix B to part 75 are applicable only to continuous emissions monitoring systems, the provisions in sections 1.3 and 1.5 of the existing rule are more generally applicable to all monitoring systems under part 75. The quality assurance requirements for excepted monitoring systems under Appendices D and E and for alternative monitoring systems under subpart E are provided in the respective Appendices or subpart of part 75, as revised; however, specific guidelines for the quality control plans for these systems are not given.

Based on the experience of state and EPA inspectors at Acid Rain field audits, there has been confusion and inconsistency among industry sources regarding the contents of the quality control plan. In some cases, utility staff have requested further guidance from EPA on what the quality control plan should contain. Based on this experience, the Agency believes that the quality control program provisions in section 1 of Appendix B need to be revised. Specifically, the rule needs to be clarified in two areas: (1) the applicability of the QA/QC program (i.e., do the provisions apply to all monitoring systems, only to CEMS, or only to specific excepted or alternative monitoring systems?); and (2) the recordkeeping requirements for repair and maintenance events. In addition, several utilities have asked EPA to consider deleting the requirement to maintain an inventory of spare parts, which they believe to be unnecessary and burdensome.

Discussion of Proposed Changes

The proposed revisions discussed in this section affect section 1 of Appendix B to part 75. The terms ''quality control program and plan'' would be changed to ''quality assurance/quality control program and plan.'' The scope of section 1 would be expanded to include QA/QC program provisions for excepted monitoring systems under Appendices D, E, and I and alternative monitoring systems under subpart E. Section 1 would also be reordered to separate the requirements applicable to all monitoring systems (section 1.1) from the requirements specific to CEMS (section 1.2). The preventative maintenance provisions, in section 1.3 of the existing rule, would be moved to section 1.1.1 of the proposal, and would be revised to delete the requirement to maintain an inventory of spare parts. A new section 1.1.3 would be added to specify the requirements for maintaining records of testing, maintenance, and repair activities. QA/QC program requirements specific to excepted monitoring systems under Appendices D, E, and I would be added in section 1.3. These provisions would require written procedures to be maintained for fuel flowmeter testing, primary element inspection, and fuel sampling and analysis as well as requiring a description of equipment and records of testing to be maintained. Section 1.3.6 would make the

recordkeeping requirements consistent with the quality assurance requirements of section 2.3.1 of Appendix E. Section 1.3.7 would specify which QA/QC program requirements apply for excepted monitoring systems under Appendix I. Finally, section 1.4 would define the QA/QC program requirements for alternative monitoring systems approved under subpart E, based on the quality assurance requirements of subpart E.

Rationale

The Agency believes that the manner in which quality assurance/quality control (QA/QC) and maintenance-related activities are performed can have a significant effect upon the accuracy of the data reported by a monitoring system. Therefore, today's proposal seeks to ensure that adequate records are kept to document that each monitoring system and its ancillary components is being maintained and operated in a proper manner. Section 1 in Appendix B to part 75 would, therefore, be amended to provide sources with General guidance regarding QA/QC program requirements. However, the Agency recognizes that QA/QC programs may vary from site to site and that many sources have already developed and implemented an effective QA/QC program. It is the Agency's intent to allow each source the flexibility to develop and implement a QA/QC program that will result in the reporting of accurate emissions data through proper equipment calibration, maintenance and troubleshooting procedures.

(a) *Inventory of Spare Parts.* Section 1.3 of Appendix B to part 75 in the January 11, 1993 rule requires that an inventory of spare parts be maintained as part of the QA/QC program. The intent of this requirement is one of the fundamental goals of a QA/QC program, i.e., to maximize the availability of quality-assured data from the monitoring system. Since maintenance and repairs are required in order to keep the monitoring system operating properly, the need for replacement parts will arise over the term of use of the monitoring equipment. In order to minimize the amount of time when the system is unable to provide data because a new part is needed, the existing rule requires that the source maintain an inventory of spare parts. The Agency has received comments on this requirement from both affected utilities and from state inspectors arguing that it is unnecessary and cumbersome (see Docket A–97–35, Item II–D–49, II–E–28). Commenters have suggested that different approaches have been effectively employed to ensure that spare parts are available in a timely manner; however, not all of these approaches require that an inventory of spare parts be kept on-site. For example, some spare parts may be available on a very timely basis from a local supplier, making it unnecessary to maintain spare parts on-site. The Agency believes that these different approaches may be adequate substitutes for keeping an on-site inventory of spare parts. Therefore, the requirement to maintain an inventory of spare parts would be removed in today's proposal, although the objective of an effective QA/QC program, i.e., to maximize data availability, would not change.

(b) *Maintenance Records.* The Agency believes that maintaining records of monitoring system maintenance and repairs is an essential component of an effective QA/QC program. Several utilities have indicated that they agree and have instituted QA/QC programs which include maintaining such records (see, e.g., Docket A–97–35, Item II–D–88). However, some EPA and state inspectors have found that not all sources keep adequate records of maintenance and repairs in their QA/QC program. EPA believes that this failure to keep adequate records compromises the effectiveness of the QA/QC program. Therefore, today's proposal would require each source to maintain proper records of all testing, maintenance, or repair activities performed on any monitoring system or component. Additionally, today's proposal would require that these records and any additional supporting documentation be made available for review during an audit.

(c) *Excepted Monitoring System Requirements.* The required quality assurance activities for excepted monitoring systems are set forth in the respective Appendices D, E, or I. Today's proposed revisions in section 1.3 of Appendix B would specify that information on the approved methods, test procedures and test results must be maintained on-site suitable for inspection as part of the QA/QC program. The proposed revisions would consolidate all of the QA/QC requirements in Appendix B rather than having them spread out in Appendices D, E, and I.

2. Flow Monitor Polynomial Coefficient

Background

Many of the stack gas volumetric flow rate monitors currently in use by affected sources use software polynomial coefficients to convert electrical signals from the monitors into flow rate values that are electronically reported to the Acid Rain Division. The flow rate values generated from these monitors are used by the source's data acquisition and handling system (DAHS) to compute hourly mass emission rates of SO_2, CO_2, and hourly heat input rates. Currently, affected sources are not specifically required to report, record, or document the numerical values of the polynomial coefficients used by their flow monitors.

Discussion of Proposed Changes

Proposed § 75.59(a)(5)(vi) and proposed revisions to section 1.1.3 of Appendix B would require the current values of the flow monitor coefficients to be recorded and would require records to be kept of any changes or adjustments to the coefficient values. The proposed revisions in § 75.20(b) define flow monitor coefficient adjustment as an event which requires recertification.

Rationale

(a) *Recordkeeping of Coefficients.* The agency has recently become aware (by a comment received in response to a request for review of the Acid Rain Audit Manual) of a potentially serious omission in the flow monitor recordkeeping requirements of part 75 (see Docket A–97–35, Item II–D–92). The commenter indicated that part 75 lacks a requirement to document the values of the polynomial coefficients which are programmed into the software of most flow monitoring devices, and that the Acid Rain CEM audit manual does not recommend that Agency or state auditors check the coefficient values. The values of the polynomial coefficients are important because they are directly related to the accuracy of a flow monitor. The coefficient values are usually established at three different load levels (low, mid, and high), in a process called ''linearization'' or ''characterization'' of the monitor. Linearization is done in an attempt to ensure that the flow monitor reads accurately across all load levels. The Agency agrees with the commenter that the flow monitor variables are a critical component of the flow monitoring system and that the adjustment of those variables represents a significant change to the flow monitoring system. Therefore, today's rulemaking proposes to add § 75.59(a)(5)(vi) to require owners and operators of affected sources to record the numerical values of the flow monitor polynomial coefficients used during initial certification of the monitor and during each subsequent relative accuracy test audit (RATA). In

addition, section 1 of Appendix B to part 75 would be revised to require that any changes to the flow monitor polynomial coefficients be documented and maintained as part of the QA/QC program maintenance records. Section 1 of Appendix B would also be changed to require the source to document procedures related to the adjustment of flow monitor variables in its QA/QC plan. The values of the flow monitor coefficients and the related adjustment procedures would be required to be kept on-site, in a format suitable for review by an inspector during an audit.

(b) *Recertification After Adjustment of Coefficients.* Since changing the flow monitor polynomial constants relinearizes the instrument, significantly altering the monitored reading, today's proposed rule would amend § 75.20(b) to require recertification subsequent to any flow monitor polynomial coefficient change. Since a three level RATA is the only part 75 quality assurance test that checks the linearity of a flow monitor, the recertification would require a three level RATA.

K. Calibration Gas Concentration for Daily Calibration Error Tests

Background

All part 75 gas monitoring systems are required by section 2.1.1 of Appendix B of the current rule to pass daily calibration error tests, in order to validate emission data from the CEMS. The procedures for conducting the daily calibration error tests are found in section 6.3.1 of Appendix A. Each daily calibration error test consists of injecting two protocol gases of known concentration into the CEMS and comparing the responses of the instrument to the tag values of the protocol gases. The two required gas concentrations for the calibration error tests are zero-level (i.e., 0.0 to 20.0 percent of the span value of the instrument) and high-level (80.0 to 100.0 percent of span).

The span values of part 75 SO_2 and NO_X monitors are determined by multiplying the maximum potential concentration (MPC) by 1.25 and rounding the result upward to the nearest 100.0 ppm. For CO_2 and O_2 monitors, a span value of 20.0 percent O_2 or CO_2 is prescribed. These span values have been deliberately oversized to prevent full-scale exceedances from occurring. Consequently, the SO_2, NO_X, CO_2, and O_2 readings obtained during normal unit operation are generally well below the span values and typically range from about 25.0 to 75.0 percent of full-scale. Because of the oversized span values, the concentrations of the high-level calibration gases used for daily calibration error tests are often much higher than the actual pollutant and diluent gas concentrations in the stack. As a result, the representativeness of the daily calibration error test can be questioned, because the test does not always check the accuracy of an analyzer on the part of the scale where most of the readings occur. For instance, typical CO_2 concentrations for many part 75 units range from about 10.0 to 12.0 percent CO_2 (i.e., 50.0 to 60.0 percent of the span value). However, when CO_2 analyzers are calibrated, the high-level calibration gas concentrations (i.e., 16.0 to 20.0 percent CO_2) are considerably higher than normal stack emissions. In view of this, EPA believes it would be appropriate to allow the owner or operator to have greater flexibility in selecting a representative upscale gas for daily calibrations. One State agency has successfully implemented this type of flexibility in its CEM program. The State's CEM rule specifies the acceptable range of values for the upscale calibration gas, but adds the following qualifying statement, ''* * *unless an alternative concentration can be demonstrated to better represent the normal source operating levels *–*–*'' (see Docket A–97–35, Item II–D–72).

Discussion of Proposed Changes

Today's rule proposes to add flexibility to the procedures for conducting the calibration error tests of part 75 gas monitors to encourage daily calibrations to be done more representatively. Section 6.3.1 of Appendix A would be revised so that, beginning on January 1, 2000, either the mid-level gas (50.0 to 60.0 percent of span) or the high-level gas (80.0 to 100.0 percent of span) could be used as the upscale calibration gas for daily calibration error tests. A corresponding change would be made to the procedure for calculating the calibration error in section 7.2.1 of Appendix A. Prior to January 1, 2000, the owner or operator would have the option of using the mid-level calibration gas for daily calibrations if it better represents the typical stack gas concentrations than the high-level gas.

L. Linearity Test Requirements

Background

Section 75.20(c) of the current part 75 rule requires a 3-point linearity test of each SO_2 and NO_X pollutant concentration monitor and each diluent gas (O_2 or CO_2) monitor, as part of the initial certification process. A linearity test consists of a series of nine reference calibration gas injections at three different known concentration levels (low, mid, and high) to establish the accuracy of a gas analyzer across its measurement range. The procedures for conducting linearity tests are found in section 6.2 of Appendix A to part 75. Section 6.1 of Appendix A specifies that linearity tests must be done while the unit is operating.

After the initial certification of a gas monitoring system, section 2.2 of Appendix B to part 75 requires periodic linearity tests to be performed. A linearity check is required during each unit operating quarter or, for bypass stacks, during each quarter in which flue gases are discharged through the stack. For units with two span values for a particular parameter (e.g., units with add-on SO_2 controls), linearity tests must be conducted on both the ''low'' and ''high'' monitor ranges. Successive linearity tests are, to the extent practicable, to be conducted no less than 2 months apart.

Utility representatives have asked EPA to consider changing the requirement for the unit to be operating when linearity tests are done (see Docket A–97–35, Items II–D–20, II–D–65, II–E–13, II–E–14). This has been requested because owners and operators of peaking units and other units that operate on an ''on-call'' basis have experienced difficulty in complying with the requirement for the unit to be on-line during linearity tests. For instance, a unit may only operate for a few hours in a quarter and not be needed again until the next quarter. In such a situation, the utility might be forced to re-start and operate the unit (whether or not it is needed) to comply with the linearity test requirement. Some of the utility representatives have also expressed the opinion that for certain monitoring technologies (e.g., dry extractive), on-line and off-line linearity tests are essentially equivalent.

Discussion of Proposed Changes

1. Unit Operation During Linearity Tests

Today's rule proposes to revise the linearity test requirements of part 75 to make them easier with which to comply. EPA agrees that the current linearity test requirements of part 75 lack flexibility and that compliance with the requirements is particularly difficult for infrequently operated units. However, the Agency does not agree with the utility representatives that have suggested allowing off-line linearity tests as the best solution to the problem. Nor is the Agency proposing to allow technology-specific exemptions to the on-line linearity test requirement.

Rather, today's proposal would retain the requirement for linearity tests to be performed while the unit is combusting fuel at conditions of typical stack temperature and pressure. A clarifying statement would be added to section 6.2 of Appendix A, indicating that the unit does not have to be generating electricity during the test. But EPA would continue to require that a linearity test be performed while the unit is combusting fuel at conditions of typical stack temperature and pressure in order to test the monitoring system under the same conditions as when the monitor is measuring emissions, in order to account for any temperature and pressure effects. An on-line linearity test challenges a CEMS while it is in equilibrium with the stack environment and has been sampling stack gas continuously for a period of time.

2. Linearity Test Frequency

The Agency proposes instead to add flexibility to the linearity test requirements by changing the basis upon which the frequency of linearity tests is determined and by providing a linearity grace period. In today's proposal, section 2.2 of Appendix B would be revised to require that a linearity test be performed in each ''QA operating quarter'' rather than in each ''unit operating quarter'' or ''bypass stack operating quarter.'' For linearity tests, a QA operating quarter would be defined in the same way as for RATAs, i.e., as a calendar quarter in which the unit operates for at least 168 hours (or, for common stacks, a quarter in which effluent gases discharge through the stack for at least 168 hours). EPA believes that the QA operating quarter methodology would, in most instances, enable the owner or operator of a peaking unit or other infrequently operated unit to complete an on-line linearity test within the calendar quarter in which it is due. However, the following additional changes would be made to further ensure that the linearity test requirements can be met: (1) the requirement to perform successive linearity tests at least 2 months apart would be reduced to allow successive tests to be done one month (30 days) apart; and (2) a new section, 2.2.4, would be added to Appendix B, providing a 168 unit operating hour grace period after the end of each QA operating quarter in which to complete the required test. Thus, to make it easier for infrequently operated units to complete the required linearity tests in the quarters in which they are due, the required waiting time between successive linearity tests would be reduced. And, if circumstances should prevent a linearity test from being completed in the QA operating quarter in which it is due, the test could be done during the grace period. If the required linearity test were not completed by the end of the grace period, data from the monitor would be considered invalid from the hour after the grace period expires until the hour of completion of a subsequent successful linearity test.

For infrequently operated units, certain calendar quarters would not qualify as QA operating quarters. Therefore, in accordance with today's proposed rule, no linearity tests would be required in those quarters. However, this exemption from linearity testing would not be without limit. Proposed section 2.2.2 of Appendix B would allow no more than four consecutive calendar quarters to elapse following the quarter in which the last linearity test was conducted, without a subsequent linearity test having to be performed. That is, a linearity test would either have to be done by the end of the fourth consecutive elapsed calendar quarter since the last test or within a 168 unit operating hour grace period after the end of the fourth consecutive elapsed quarter. Data from the monitor would become invalid if the linearity test was not completed by the end of the grace period and would remain invalid until a linearity test was successfully completed.

Today's proposal would also change the requirement for units with two span values for a particular parameter (e.g., units with add-on SO_2 controls) to perform quarterly linearity tests on both the low and high monitor ranges. Section 2.2.1 of Appendix B would be revised to require a linearity test of a monitor range only if that range is used to report data during the QA operating quarter. However, under proposed section 2.2.3(e) of Appendix B, at least one linearity test of each range would still be required every four calendar quarters to maintain data validation on the range.

3. Linearity Test Method

Today's proposal would add two new requirements to section 6.2 of Appendix A: (1) that all linearity tests must be done ''hands-off,'' meaning that no adjustments of the CEMS other than certain calibration error adjustments would be permitted prior to or during the linearity test period; and (2) to the extent practicable, each linearity test would have to be completed within a period of 24 unit operating hours. These proposed provisions are intended to ensure greater consistency in the way in which linearity tests are conducted and to ensure that the tests are completed in a timely manner. The allowable calibration adjustments prior to and during a linearity test would be defined in proposed section 2.1.3 of Appendix B. For a further discussion, see Section O of this preamble, ''CEM Data Validation,'' below.

4. Exemptions

Finally, section 6.2 of Appendix A would be revised to exempt SO_2 and NO_X monitors with span values of 30 ppm or less from the linearity test requirements of part 75. At these low span values, the linearity test begins to lose its significance. For example, typical low, mid, and high calibration gases for a span value of 30.0 ppm would be 24.0 ppm, 18.0 ppm, and 9.0 ppm, respectively. The appropriate linearity performance specification in section 3.2 of Appendix A is ± 5.0 ppm at each calibration gas level. Therefore, in this illustration, the monitor reading could be 14.0 ppm for both the ''low'' and ''mid'' gases or 20.0 ppm for both the ''mid'' and ''high'' gases. Even though a valid straight line comparing the reference gas concentrations and the monitor readings cannot be constructed from such data, the monitor would still appear to pass the linearity test.

M. Flow-to-Load Test

Background

The current quality assurance requirements for flow rate monitoring systems in Appendices A and B to part 75 include daily calibration error tests, daily interference checks, quarterly leak checks (for differential pressure type monitors only), and semiannual or annual relative accuracy test audits. Of these required QA tests, only the RATA provides a true evaluation of a flow monitor's measurement accuracy by direct comparison against an independent reference method. The daily calibration error test purports to check flow monitor accuracy, but, as explained below, the ability of the test to accomplish this objective is somewhat questionable.

There is a distinct difference between the daily calibration error test of a flow rate monitor and the calibration error test of a gas monitor. To calibrate a gas monitor, a protocol gas of known concentration is sent through the monitoring system and analyzed. This generally serves as a reliable indicator of the system's ability to accurately measure pollutant or diluent gas concentrations, because the calibration closely simulates the sampling and analysis of stack gas by the monitoring

system. A flow monitor calibration error test, on the other hand, does not provide the same level of assurance of data quality. Generally, a flow monitor calibration checks the system's internal electronic components by means of reference signals. The calibration error test is useful in that it can diagnose certain types of monitor problems, but it is not a ''true'' calibration of the monitor, since it does not evaluate the system's ability to measure an actual stack gas flow rate. In order to perform true daily flow monitor calibrations, two reference stack gas flow rates would have to be generated and measured. Practical considerations preclude such calibrations from being done, however, because the unit load level would have to be significantly varied during each operating day, and suitable reference method measurements (e.g., velocity traverses using EPA Method 2) would have to be made daily at each calibration load level.

Because of the limited usefulness of the flow monitor daily calibration error test, EPA believes that a more substantive, periodic QA test is needed to ensure that the accuracy of the reported flow rate data is maintained in the interval between successive RATAs. The Agency is particularly concerned about the potential for poor data quality from flow monitors that are not properly maintained. For instance, the sensors of DP and thermal-type monitors are subject to plugging and/or fouling, which will cause the monitors to read lower than true and can result in under-reporting of emissions. One utility observed a substantial increase in the readings from its flow monitor after the sensors were cleaned during a unit outage. Apparently, the sensor problems had not been detected by the daily calibration error tests (see Docket A–97–35, Item II–E–29). A second utility experienced a gradual deterioration of the monitor's performance in the 9-month period following the RATA. By the sixth month (at load levels and CO_2 concentrations virtually identical to the conditions at the time of the RATA), the flow monitor readings were consistently 15.0 to 20.0 percent lower than the baseline average flow rate measured by EPA Reference Method 2 during the RATA. However, during the 9-month period, the flow monitor had consistently passed its daily calibration error tests (see Docket A–97–35, Item II–B–11). During a State inspection of a third utility, the inspector observed a consistent 20.0 to 30.0 percent difference between the hourly flow rates measured by the primary and redundant backup flow monitors even though both monitors had been passing their daily calibration error tests. In this instance, the primary flow monitor was being used for data reporting and was reading higher than the redundant backup monitor; therefore, it is unlikely that emissions were being under-reported. Had the primary monitor malfunctioned and the redundant backup been used, however, emissions would have been significantly under-reported (see Docket A–97–35, Item II–B–10).

Discussion of Proposed Changes

In view of the apparent shortcomings of the flow monitor daily calibration error test, EPA proposes to add a new flow monitor quality assurance test, the ''flow-to-load test,'' to part 75. The flow-to-load test, which would be performed quarterly, is described in proposed sections 7.7 of Appendix A and 2.2.5 of Appendix B. The proposed quarterly flow-to-load test would be required beginning in the first quarter of the year 2000.

The basic premise of the flow-to-load test is that a meaningful correlation exists between the stack gas volumetric flow rate and unit load. In general, for a single unit discharging to a single stack, as the load increases, the flow rate increases proportionally, and the flow rate at a given load should remain relatively constant if the same type of fuel is burned (see Docket A–97–35, Items II–B–9, II–D–69). Common stacks are somewhat less predictable, because the same combined unit load can be produced in a number of ways by using different combinations of boilers. Despite this, if the diluent gas concentration is properly taken into account, the flow-to-load characteristics of common stacks often become more normalized (see Docket A–97–35, Items II–B–9, II–D–73, II–D–74, II–D–76, II–D–83, II–D–84). The flow-to-load ratio, or a normalized ratio, can thus serve as a quantitative indicator of flow monitor accuracy from quarter to quarter until the next RATA is performed.

The quarterly flow-to-load ratio test would be conducted as follows. The owner or operator would be required to determine R_{ref}, a reference value of the ratio of flow rate to unit load, each time that a successful normal-load flow RATA is performed. The value of R_{ref} would be reported in the electronic quarterly report required under § 75.64, along with the completion date of the associated RATA. If two load levels (e.g., mid and high) are designated as normal, the owner or operator would determine a separate R_{ref} value for each normal load level. The reference flow-to-load ratio would be calculated as follows:

$$R_{ref} = \frac{(Q_{ref})}{L_{avg}} \times 10^{-5}$$

In the equation above, R_{ref} is the reference value of the flow-to-load ratio from the most recent normal-load flow RATA; Q_{ref} is the average stack gas volumetric flow rate (in scfh) measured by the reference method during the normal-load RATA; and L_{avg} is the average unit load during the normal-load flow RATA. For a common stack, L_{avg} would be the sum of the operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks or ducts, Q_{ref} would be the sum of the total volumetric flowrates that discharge through all of the stacks (or ducts). The reference flow-to-load ratio would be rounded off to 2 decimal places.

As an alternative, the owner or operator could calculate a reference value of the gross heat rate (GHR) in lieu of R_{ref}. In order to exercise this option, quality assured diluent gas (CO_2 or O_2) data would have to be available for each hour of the most recent normal-load flow RATA. The reference value of the GHR would be determined as follows:

$$(GHR)_{ref} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000$$

In the equation above, $(GHR)_{ref}$ is the reference value of the gross heat rate at the time of the most recent normal-load flow RATA; $(\text{Heat Input})_{avg}$ is the arithmetic average hourly heat input during the normal-load flow RATA; and L_{avg} is the average unit load during the normal-load flow RATA. In calculating $(\text{Heat Input})_{avg}$, the average volumetric flow rate measured by the reference method during the RATA would be used in conjunction with the average diluent gas concentration measured during the RATA, substituting these values into the applicable heat input equation in Appendix F.

After establishing the reference flow-to-load or GHR value, an evaluation of the flow-to-load ratio or GHR would be required for each primary and redundant backup flow monitor on a quarterly basis. The owner or operator would be required to evaluate the flow-to-load ratio in each ''QA operating quarter'' (i.e., each quarter in which the unit or stack operates for at least 168 hours). At the end of each QA operating quarter, the owner or operator would calculate the flow-to-load ratio for every hour during the quarter in which: (1) the unit (or combination of units, for a common stack) operated within ±10.0 percent of L_{avg}, the average load during the most recent normal-load flow

RATA; and (2) a quality assured hourly average flow rate was obtained with a certified flow rate monitor. The owner or operator would have the option of using either bias-adjusted flow rates or unadjusted flow rates in the hourly flow-to-load ratios, provided that all of the ratios were calculated the same way. EPA had originally considered proposing that only unadjusted flow rates should be used to calculate the flow-to-load ratios. However, in response to comments received from CEMS Utility Workgroup members, the Agency is proposing to allow either unadjusted or bias-adjusted flow rates to be used, on the condition that the acceptance criteria for the flow-to-load test would be more stringent if bias-adjusted flow rates are used (see Docket A–97–35, Item II–D–82).

For a common stack, the ''load'' in each hourly flow-to-load ratio would be the sum of the hourly operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks (or for a unit that monitors total flow rate in multiple ducts or breechings), the ''flow'' in the flow-to-load ratio would be the combined hourly volumetric flow rate through all of the stacks (or ducts). Each hourly flow-to-load ratio would be rounded off to 2 decimal places.

Alternatively, the owner or operator could calculate the hourly gross heat rate (GHR) values in lieu of the hourly flow-to-load ratios. However, an hourly GHR could only be determined for those hours within ±10.0 περψεντ οφ Λ_{avg} for which quality assured flow rate and diluent gas (CO_2 or O_2) concentration data are available from a certified CEMS or reference method. The owner or operator could use either bias-adjusted flow rates or unadjusted flow rates to determine the hourly GHR values.

The calculated hourly flow-to-load ratios (or gross heat rates) would be analyzed at the end of the quarter. A separate data analysis would be performed for each primary and each redundant backup flow rate monitor used to record and report data during the quarter. Each analysis would be based on a minimum of 168 hours of data. If two RATA load levels are designated as normal, the analysis would be performed at the higher load unless fewer than 168 data points were available at that load, in which case, the analysis would be performed at the lower load. If, for a particular flow monitor, fewer than 168 hourly flow-to-load ratios (or GHR values) were available at any normal load level, a flow-to-load (or GHR) evaluation would not be required for that monitor for that calendar quarter.

For each flow monitor, E_h, the difference (absolute value) between each hourly flow-to-load ratio and R_{ref}, would be expressed as a percentage of R_{ref} (or, if the GHR is used, the absolute difference between each hourly GHR value and $(GHR)_{ref}$ would be expressed as a percentage of $(GHR)_{ref}$). Then, E_f, the arithmetic average of all of the E_h values, would be calculated. Note that R_{ref} would always be based upon the most recent normal-load RATA, even if that RATA was performed in the calendar quarter being evaluated.

The owner or operator would be required to report the results of each quarterly flow-to-load (or GHR) evaluation in the electronic quarterly report required under § 75.64. The results of a quarterly flow-to-load (or GHR) evaluation would be considered acceptable, and no further action would be required if the average absolute percentage difference (E_f) did not exceed the following limits:

(i) 15.0 percent, if L_{avg} for the most recent normal load flow RATA is ≥ 50 megawatts (or ≥ 500 klb/hr of steam) and if unadjusted flow rates were used in the calculations;

(ii) 10.0 percent, if L_{avg} for the most recent normal load flow RATA is ≥ 50 megawatts (or ≥ 500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations;

(iii) 20.0 percent, if L_{avg} for the most recent normal load flow RATA is < 50 megawatts (or < 500 klb/hr of steam) and if unadjusted flow rates were used in the calculations;

(iv) 15.0 percent, if L_{avg} for the most recent normal load flow RATA is < 50 megawatts (or < 500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations.

If E_f exceeded the applicable limit, the owner or operator would have two available options: (1) perform a RATA, as described in proposed section 2.2.5.2 of Appendix B, unless a monitor malfunction is diagnosed and corrected, in which case an abbreviated flow-to-load test could be performed, in lieu of a RATA, in accordance with section 2.2.5.3 of Appendix B and discussed below; or (2) re-examine the hourly data used for the flow-to-load or GHR analysis and recalculate E_f, after excluding all non-representative hourly flow rates. If the owner or operator were to choose option (2), i.e., to recalculate E_f, only the flow rates for the following hours would be considered non-representative and could be excluded from the data analysis:

(1) Any hour in which the type of fuel combusted was different from the fuel burned during the most recent normal-load RATA. The type of fuel would be different if the fuel is in a different state of matter (i.e., solid, liquid, or gas) or is a different classification of coal (e.g., bituminous versus sub-bituminous) than the fuel burned during the RATA;

(2) Any hour in which an SO_2 scrubber was bypassed;

(3) Any hour in which ''ramping'' occurred, i.e., the hourly load differed by more than + 15.0 percent from the load during the preceding hour or the subsequent hour;

(4) If a normal-load flow RATA was performed and passed during the quarter being analyzed, any hour prior to completion of that RATA; and

(5) If a problem with the accuracy of the flow monitor was discovered during the quarter and corrected, any hour prior to completion of the subsequent diagnostic test described in proposed section 2.2.5.3 of Appendix B, confirming that the corrective actions were successful.

After identifying and excluding any non-representative hourly data in accordance with (1) through (5) above, the owner or operator could analyze the remaining data a second time. At least 168 representative hourly ratios or GHR values at normal load would have to remain in order to perform the analysis; otherwise, the flow-to-load (or GHR) analysis would not be required for that monitor for that calendar quarter.

If, after re-analyzing the data, E_f is found to be within the applicable limit in (i), (ii), (iii), or (iv), above, then no further action would be required. However, if E_f is still outside the applicable limit, the monitor would be declared out-of-control as of the first hour of the quarter following the quarter in which the flow-to-load test was failed. The owner or operator would then perform a RATA as described in proposed section 2.2.5.2 of Appendix B, unless, as the result of an investigation, an instrument malfunction is discovered and corrected as described in proposed section 2.2.5.1 of Appendix B.

If a problem with the monitor is identified, all corrective actions (e.g., non-routine maintenance, repairs, major component replacements, re-linearization of the monitor, etc.) would have to be documented in the operation and maintenance records for the monitor. Data from the monitor would remain invalid until a ''probationary'' calibration error test of the monitor was passed following completion of all corrective actions, at which point data from the monitor would be assigned a ''conditionally valid'' status. The owner or operator would then perform an abbreviated flow-to-load test (found in proposed section 2.2.5.3 of Appendix B) to verify that the corrective actions were

effective, unless the linearity of the flow monitor was affected by the corrective actions (e.g., by the changing of its polynomial coefficients). If the flow monitor linearity was affected, the owner or operator would no longer have the option of performing the abbreviated flow-to-load test in section 2.2.5.3 of Appendix B, but would instead be required to perform a 3-load recertification RATA in accordance with the recertification test period and data validation procedures of § 75.20(b)(3).

The abbreviated flow-to-load test in proposed section 2.2.5.3 of Appendix B is based on a recertification policy developed jointly by EPA, several utility representatives, and one flow monitor vendor (see Docket A–97–35, Items II–B–1, II–D–70, II–I–9, and II–I–16). Use of the abbreviated flow-to-load test would not be limited to situations in which a quarterly flow-to-load test has been failed. Rather, the test could be performed after any documented repair, component replacement, or other corrective maintenance to a flow monitor (except for changes affecting the linearity of the flow monitor, such as adjusting the flow monitor coefficients) to demonstrate that the repair, replacement, or other corrective maintenance has not significantly affected the monitor's ability to accurately measure the stack gas volumetric flow rate. Data from the monitoring system would be considered invalid from the hour of commencement of the repair, replacement, or other corrective maintenance until the hour in which a ''probationary'' calibration error test is passed following completion of the repair, replacement, or other corrective maintenance and any associated adjustments to the monitor. The abbreviated flow-to-load test would have to be completed within 168 unit operating hours of the probationary calibration error test (or, for peaking units, within 30 unit operating days, if that is less restrictive). Data from the monitor would be considered ''conditionally valid'' (as defined in § 72.2) beginning with the hour of the probationary calibration error test.

Following a flow-to-load test failure, the abbreviated flow-to-load test could be performed if the investigation into the cause of the test failure revealed a problem with the flow monitor and the problem was subsequently corrected without having to re-linearize the flow monitor. The test procedures would be as follows. The unit(s) would be operated in such a way as to reproduce, as closely as practicable, the exact conditions at the time of the most recent normal load flow RATA. To achieve this, the load should be held constant to within ± 5.0 percent of the average load during the RATA, and the diluent gas (CO_2 or O_2) concentration should be maintained within ± 0.5 percent CO_2 or O_2 of the average diluent concentration during the RATA. For common stacks, to the extent possible, the same combination of units and load levels that were used during the RATA should be used. When the process parameters have been set, a minimum of 6 and a maximum of 12 consecutive hourly average flow rates would be recorded using the flow monitor(s) for which E_f was outside the applicable limit. For peaking units, a minimum of 3 and a maximum of 12 consecutive hourly average flow rates would be required. The corresponding hourly load values and, if applicable, the hourly diluent gas concentrations would also be recorded. The flow-to-load ratio or the GHR would be calculated for each hour in the test hour period using proposed Equation B–1 or B–1a in Appendix B. Then, E_h would be determined for each hourly flow-to-load ratio or GHR using proposed Equation B–2 in Appendix B. Finally, E_f , the arithmetic average of the E_h values, would be determined.

The results of the abbreviated flow-to-load test would be considered acceptable, and no further action would be required if the value of E_f did not exceed the applicable limit specified in proposed section 2.2.5.1 of Appendix B. All conditionally valid data recorded by the flow monitor would then be considered quality assured, beginning with the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test. However, if E_f was found to be above the applicable limit, all conditionally valid data recorded by the flow monitor would be considered invalid back to the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test, and a single-load RATA would be required, in accordance with proposed section 2.2.5.2 of Appendix B.

When a single-load RATA is performed because the owner or operator is unable to reconcile a quarterly flow-to-load test failure, either by excluding non-representative hours and recalculating E_f or by passing the abbreviated flow-to-load test after performing component replacement or other corrective maintenance on the flow monitor, then data from the monitor would remain invalid until the hour of successful completion of the single-load RATA.

Rationale

EPA believes that the proposed methodology for the quarterly flow-to-load test is fundamentally sound. It has been developed through a series of teleconferences and face-to-face meetings between EPA, members of the regulated community, and State and local agency personnel (see Docket A–97–35, Items II–D–77, II–D–80, II–D–81, II–D–82, II–D–85, II–E–23, II–E–24, II–E–25, II–E–26, and II–E–28). In addition, some provisions of the flow-to-load test were revised following pre-proposal comment. Specifically, the proposal reflects, in section 2.2.5.1 (b) of Appendix B to part 75, a commenter's request that if a quarterly flow-to-load test is failed and the monitor malfunction is discovered and corrected (without the need to relinearize the monitor), the correction could be verified using the abbreviated flow-to-load test in lieu of performing a single load RATA (see Docket A–97–35, Item II–D–42).

The proposed tolerance limits set forth in paragraphs (i), (ii), (iii), and (iv) of section 2.2.5 of Appendix B are believed to be both reasonable and achievable. When these tolerance limits are met, it provides a strong indication that the flow monitor is still accurate to within 10.0 percent of the reference method baseline established during the last normal-load flow RATA and would, therefore, appear to be in control with respect to the relative accuracy requirements of part 75. An extra tolerance of 5.0 percent has been incorporated into the limits to account for imprecision in the flow-to-load methodology. An extra 5.0 percent tolerance has also been added for smaller units (i.e., normal load less than 50 megawatts or 500 klb/hr of steam), because the flow-to-load ratio or GHR for such units is very sensitive to small variations in load (see Docket A–97–35, Item II–B–7).

To test the viability of the proposed tolerance limits, EPA analyzed quarterly flow rate and load data from the third quarter of 1996 for 21 units and stacks, including 9 single units, 11 common stacks, and 1 multiple-stack unit (see Docket A–97–35, Items II–A–1, II–A–2, II–A–3). The units chosen for this analysis were selected as a representative sample of units that would be affected by this QA test requirement and included various operational circumstances (e.g., baseloaded and peaking units, single fuel units, and units that burn multiple fuels). The flow-to-load test was applied to each unit or stack in the manner described above, except that *no* hours within ± 10.0 percent of L_{avg} were excluded from the data analysis. The data from these same units plus one additional multiple-stack unit were

analyzed a second time, with each flow-to-load ratio being multiplied by the diluent gas concentration. This is similar, but not identical, to calculating the GHR. Once again, no hours within ± 10.0 percent of L_{avg} were excluded. In both analyses, *unadjusted* flow rates were used in the ratios. The results of the two data analyses were nearly the same. Only one failure of the quarterly flow-to-load test was observed in each analysis (i.e., the failure rate was < 5.0 percent). The average value of E_f was 6.1 percent for the analysis without the diluent gas corrections and 6.4 percent for the analysis with the diluent gas corrections. A few units and stacks had a much lower E_f value when the diluent correction was applied, but in most cases, the diluent correction had relatively little effect. These results suggest that the flow-to-load test can provide EPA with the necessary assurance that flow monitors continue to generate accurate data from one RATA to the next. The results also indicate that the test should be relatively easy to pass if flow monitors are properly maintained and operated.

Because of the added quality assurance that would be provided by performing the flow-to-load or GHR test each quarter, EPA has reconsidered the scope of the other quality assurance tests for flow monitors. In today's proposed rule, the Agency is proposing to reduce the annual 3-load flow RATA requirement to a 2-load RATA and to reduce the frequency of 3-load RATAs to once every five years (and whenever a flow monitor is re-linearized). In addition, single-load flow RATA testing would be allowed in lieu of the annual 2-load test if the facility could demonstrate that a unit has operated at a single load level for at least 85.0 percent of the time in the four ''QA operating quarters'' prior to the scheduled RATA. (See Section N.2 of this preamble, below, for further discussion.) The Agency believes that, taken together, these proposed changes will reduce the cost and burden of quality assurance testing for flow monitors, while ensuring high data quality. The proposed reduction in the amount of required RATA testing is considered feasible because of the increased quality assurance provided by the quarterly flow-to-load test. EPA requests comment on the proposed revisions to flow monitor quality assurance requirements.

N. RATA and Bias Test Requirements

Background

Section 6.5 of Appendix A to the January 11, 1993 rule, as amended on May 17, 1995 and November 20, 1996, requires relative accuracy test audits of all primary and redundant backup SO_2, NO_X, CO_2, and flow monitoring systems to be performed during the initial certification of the CEMS. A RATA consists of a series of 9 or more simultaneous test runs, comparing measurements made by the continuous monitoring system against an EPA reference test method. The procedures for conducting RATAs are found in section 6.5 of Appendix A to part 75.

Following the initial certification of a CEMS, section 2.3 of Appendix B to part 75 requires that periodic RATAs of gas and flow monitors be performed to quality assure the data from the CEMS on an on-going basis. The frequency at which relative accuracy testing is required depends upon the results of the last RATA of a monitoring system. Part 75 currently requires RATAs to be performed semiannually, unless a monitoring system achieves a low enough relative accuracy to qualify for an annual test frequency. The Agency has always interpreted ''semiannually'' to mean that the deadline for the next RATA is the end of the second calendar quarter following the quarter in which a RATA is successfully completed, and ''annually'' to mean that the next RATA is due by the end of the fourth calendar quarter following the quarter in which a RATA is successfully completed. For monitors installed on peaking units and bypass stacks, however, the RATA deadlines are based on operating quarters, not calendar quarters. That is, the next RATA is due either at the end of the second or fourth unit operating quarter (for peaking units) or bypass stack operating quarter following the quarter in which a RATA is successfully completed.

For SO_2, NO_X, and CO_2 monitors, the RATAs are to be conducted while the unit is operating at normal load and while combusting the fuel that is normal for the unit. Flow monitor RATAs are to be conducted at three different loads, evenly spaced over the operating range of the unit. When a flow monitor is on a semiannual RATA frequency, a normal-load RATA rather than a 3-load RATA may be conducted to satisfy the semiannual test requirement, but a 3-load RATA is still required annually. Note that for flow monitors installed on peaking units and bypass stacks, 3-level flow RATAs are not required; RATAs are performed only at the normal load.

For SO_2, NO_X, and flow monitoring systems, section 7.6 of Appendix A requires that each time a RATA is successfully completed, a bias test be performed to determine if the system has a low measurement bias. If a monitoring system fails the bias test, a ''bias adjustment factor'' (BAF) must be applied to all subsequent emission data reported from that monitoring system. For 3-load flow RATAs, the bias test is done at the normal load. If a flow monitor fails the normal-load bias test, then a BAF must be calculated at each of the three load levels, and the highest of the three BAFs is applied to all flow data reported from the monitor.

When a RATA is due, section 2.3.1 in Appendix B of the rule allows the owner or operator two attempts to achieve an annual RATA frequency and/or a favorable BAF. If a second attempt is made, the RATA frequency and BAF obtained in the second RATA supersede the results of the first RATA. Once the RATA frequency has been established as semiannual or annual, section 2.3.1 of Appendix B specifies that (to the extent practicable) the next RATA of the CEMS may not be done until at least four months have elapsed.

Finally, § 75.21(a)(6) of the November 20, 1996 rule provides an exemption from the RATA requirements of part 75 for SO_2 monitors installed on units that burn only natural gas or fuel with a sulfur content no greater than natural gas. For units that burn both gas and higher-sulfur fuel, such as oil, as primary or backup fuels, § 75.21(a)(5) requires that the RATA of the SO_2 monitor be done when the higher-sulfur fuel is burned. Section 75.21(a)(7) further states that calendar quarters in which only fuel with a sulfur content no greater than natural gas is burned are to be excluded in determining the deadline for the next SO_2 monitor RATA.

Two utility groups, UARG and the Class of '85, have requested that EPA consider revising the RATA requirements of part 75 to make them more flexible, easier with which to comply, and less costly. Some of the possible changes suggested by these groups are as follows: (1) reduce the frequency of required RATAs; (2) determine RATA deadlines based on the amount of unit operation since the last RATA, rather than the number of calendar quarters that have elapsed; (3) remove the requirement to achieve a more stringent relative accuracy standard in order to obtain an annual RATA frequency; (4) except for initial certification, allow flow RATAs to be done at a single load; (5) allow single-point sampling during gas RATAs; and (6) allow a grace period in which to complete a RATA whenever a deadline is not met (see Docket A–97–35, items II–D–20, II–D–30, II–D–65, II–E–13, II–E–14).

Discussion of Proposed Changes

EPA is proposing revisions to the RATA requirements of part 75 based upon experience gained through implementation of the rule and in light of the recommendations made by the utility groups. Today's rulemaking sets forth the proposed changes, which are intended to make the RATA requirements less burdensome without sacrificing data quality.

1. RATA Frequency

EPA does not propose to revise the basic semiannual and annual RATA requirements of part 75 or the incentive system by which to obtain an annual RATA frequency (i.e., to obtain the reduced frequency, a better percentage relative accuracy is required). Instead, the Agency proposes to re-define the terms ''semiannual RATA frequency'' and ''annual RATA frequency,'' and to change the method by which RATA deadlines are determined.

Today's rule proposes to amend section 2.3 of Appendix B so that the deadline for the next RATA is determined on the basis of ''quality assurance operating quarters,'' rather than calendar quarters. This change would apply, with few exceptions, to all primary and redundant backup monitoring systems, including monitors installed on peaking units and bypass stacks. A ''QA operating quarter'' would be defined as a calendar quarter in which a unit operates for at least 168 hours or, for common-stacks and bypass stacks, a quarter in which flue gases discharge through the stack for at least 168 hours.

Any calendar quarter that does not qualify as a QA operating quarter would be excluded in determining the deadline for the next RATA. EPA therefore proposes to re-define the term ''semiannual RATA frequency'' to mean that the next RATA is due at the end of the second QA operating quarter following the quarter in which a RATA is successfully completed. Similarly, ''annual RATA frequency'' would mean that the next RATA is due at the end of the fourth QA operating quarter following the quarter in which a RATA is successfully completed.

The QA operating quarter methodology has been proposed principally for the benefit of cycling and peaking units to make the part 75 RATA requirements easier to meet. The proposed methodology will not greatly affect base-loaded units, since they seldom operate for less than 168 hours in a quarter. For base-loaded units, the QA operating quarter method is, in most instances, equivalent to the familiar calendar quarter scheme for determining RATA deadlines. Note, however, that on occasion a base-loaded unit may obtain an extended RATA deadline by the QA operating quarter methodology, e.g., when the unit goes into an extended outage (planned or forced) and experiences one or more quarters in which the unit operates for less than 168 hours.

Although the QA operating quarter method allows RATA deadlines to be extended by the exclusion of quarters in which the unit(s) operate for less than 168 hours, such exclusion of calendar quarters is not without limit. Section 2.3.1.1 of Appendix B proposes to allow a maximum of eight consecutive calendar quarters to elapse following the quarter in which the last RATA was performed. A RATA would either have to be performed by the end of the eighth consecutive elapsed calendar quarter since the last RATA or within a 720 unit operating hour ''grace period'' following the end of the eighth consecutive elapsed quarter. Failure to complete a RATA within the grace period would cause data from the monitoring system to become invalid from the hour of expiration of the grace period until the hour of completion of a successful RATA.

Although the proposed QA operating quarter methodology would serve as the basis for determining the RATA deadline for most routine quality assurance RATAs, there are five notable instances in the current rule or in today's proposal where the RATA deadline is either not determined solely on that basis or is determined entirely on another basis. The first instance is for a unit that burns both natural gas (or fuel with equivalent total sulfur content) and other higher-sulfur fuels as primary or backup fuels and that uses an SO_2 monitor to account for SO_2 mass emissions. Section 75.21(a)(7) of the current part 75 (redesignated as § 75.21(a)(9) in today's proposal) specifies that irrespective of the number of hours of unit operation in the quarter, any calendar quarter in which natural gas (or fuel with a total sulfur content no greater than the total sulfur content of natural gas) is the only fuel combusted in the unit (i.e., a ''gas-only'' quarter) is to be excluded in determining the deadline for the next RATA of the SO_2 monitoring system. Section 75.21(a)(5) of the current rule further states that for such units, the RATA of an SO_2 monitoring system is to be performed only when the higher-sulfur fuel is being combusted. Second, as discussed in section III.N.6 of this preamble, § 75.21(a)(7) of today's proposed rule would conditionally exempt from SO_2 RATA requirements any unit certified by the designated representative to burn fuel(s) with a sulfur content greater than natural gas only as emergency backup fuel or for short-term testing, provided that the annual usage of the higher-sulfur fuel(s) is kept below 480 hours. However if, during any quarter, the annual usage of the higher-sulfur fuel exceeded 480 hours, an SO_2 RATA would be required either in that quarter or during a subsequent grace period. Thus, for RATAs of SO_2 monitoring systems, it is evident that the number of unit operating hours in a calendar quarter is not the only consideration that determines the deadline for the next RATA; the total sulfur content of the fuel being combusted must also be considered. Third, as discussed in section III.O.6 of this preamble, for certain non-redundant backup monitoring systems, § 75.20(d) of today's proposal would require a periodic RATA every eight *calendar* quarters (rather than QA operating quarters). Fourth, as discussed in section III.N.2 of this preamble, under section 2.3.1.3 of Appendix B in today's proposal, 3-level flow RATAs would have to be performed once in every period of five consecutive *calendar* years (e.g., prior to permit renewal) and whenever a flow monitor is re-linearized. Fifth, as discussed in section III.O.4 of this preamble, for recertification RATAs, which are not regularly scheduled tests, but are done on an ''as-required'' basis, § 75.20(b)(3) of today's proposal specifies that the deadline for completing such RATAs would be 720 unit operating hours after the start of the recertification test period.

2. RATA Load Levels

Today's proposed rule would more clearly define the load levels at which RATAs are done in order to provide greater consistency in the way that RATAs are performed. The current provisions of part 75 are neither sufficiently standardized nor clear in defining the appropriate RATA load levels, particularly for flow RATAs. For example, section 6.5.2 of Appendix A specifies that the ''low'' load audit point for a 3-level flow RATA can be located anywhere from the minimum safe, stable load to 50.0 percent of the maximum load. Also, there is no minimum required load separation between the audit points at adjacent load levels. If adjacent audit points are too close together, a 3-level flow evaluation loses its significance. Finally, while the current rule requires gas and flow RATAs to be conducted at normal

load, no definition of normal load is provided. It could be inferred from the current section 6.5.2 of Appendix A that the ''mid'' load level is considered normal because it requires the 3-load RATA to be done at a frequently used low load, a frequently used high operating load, and a normal load. However, experience in implementing the program has shown that for many units, the high load level is considered normal by the facility. For a few units, low load is considered normal, and for still others, the normal load can depend upon the time of day or the season of the year.

Proposed section 6.5.2.1 of Appendix A would therefore require the owner or operator first to define the ''range of operation'' for each unit or common stack equipped with hardware CEMS. The range of operation would extend from the minimum safe, stable load to the ''maximum sustainable load,'' which is the higher of: (a) the nameplate capacity of the unit (less any physical or regulatory deratings), or (b) the highest sustainable load, based on at least four quarters of representative historical data. For a common stack, the lower boundary of the range of operation would be the lowest minimum safe, stable load for any of the individual units using the stack. The upper boundary of the range would be obtained by adding together the maximum sustainable loads of all units using the stack, or if that combined load is unattainable in practice, by using the highest sustainable combined load based on at least four quarters of representative historical data. Three load levels would then be defined in terms of the range of operation. The ''low'' level would be the lower 30.0 percent of the range; the ''mid'' level would be the central portion (30.0 percent to 60.0 percent) of the range; and the ''high'' level would be 60.0 percent to 100.0 percent of the range. Proposed section 6.5.2 of Appendix A would specify that for multi-level flow RATAs, the audit points at adjacent load levels (e.g., low and mid, or mid and high) must be separated by no less than 25.0 percent of the range of operation. The owner or operator would be required to report the upper and lower boundaries of the range of operation in the electronic quarterly report required under § 75.64.

Section 6.5.2.1 of Appendix A in today's proposal would further require the owner or operator to determine, for each unit or common stack on which CEMs are installed (except for peaking units), the two load levels (low, mid, or high) that are the most frequently used. The two-fold purpose of this determination, which would be required, at a minimum, annually (just prior to the annual quality assurance RATAs and in the same calendar quarter as the RATAs), would be to identify the normal load level(s) and to identify the two load levels that are the most appropriate for annual 2-level flow monitor audits and for flow monitor bias adjustment factor calculations. To make the determination, the owner or operator would construct an historical load frequency distribution (e.g., histogram), depicting the relative number of operating hours at each of the three load levels, low, mid, and high. The frequency distribution would be based upon all available data from the four most recent QA operating quarters, as defined in proposed section 2.3.1.1 of Appendix B. The load frequency distribution would be used to determine the percentage of the time (to the nearest 0.1 percent) that each load level (low, mid, and high) has been used in recent history and thereby to identify the two most frequently used load levels. A summary of the data used for these determinations would be maintained on-site in a format suitable for inspection, and the results of the determinations would be included in the electronic quarterly report under § 75.64. The proposed revisions discussed in this paragraph would become effective as of January 1, 2000.

The owner or operator would be required under proposed section 6.5.2.1 of Appendix A to designate the most frequently used load level (low, mid, or high) as the normal load level for each unit or common stack (except for peaking units). The owner or operator would also have the option of designating the second most frequently used load level as an additional normal load level. Today's proposal would, therefore, not limit normal load to a single load level. This way of defining normal load is particularly appropriate for units that operate on a diurnal cycle and units that operate at distinctly different load levels during different seasons of the year due to ambient conditions, electrical demand, etc. EPA believes that the added flexibility in the definition of normal load (i.e., not confining it to a single load level) will allow the normal-load RATA requirements of part 75 to be more easily met. The owner or operator would be required to identify the selected normal load level(s) in the electronic quarterly report required under § 75.64. For peaking units, the entire range of operation would, for simplicity, be considered normal.

Revisions to section 2.3.1.3 of Appendix B are proposed in today's rule, requiring the routine quality assurance RATAs of flow monitors to be done as follows. For flow monitors installed on peaking units and bypass stacks, no changes are proposed; the requirement to perform only single-load flow RATAs at normal load would be retained. For all other flow monitors, the routine semiannual and annual RATAs would be done at 2 loads (i.e., the two most frequently used load levels, as identified in section 6.5.2.1 of Appendix A), with two exceptions: (1) the 2-load flow RATA could be performed alternately with a single-load flow RATA at the most frequently used (normal) load level, if the flow monitor is on a semiannual RATA frequency; and (2) a single-load flow RATA at the most frequently used load level could be performed in lieu of the 2-load RATA if, for the four QA operating quarters prior to the quarter in which the RATA is conducted, the historical load frequency distribution constructed under section 6.5.2.1 of Appendix A shows that the unit has operated at the most frequently used load level for ≥ 85.0 percent of the time. For all units, the requirement to perform periodic 3-load flow RATAs would be retained, but the frequency would be changed from annual to once every five calendar years. A 3-load RATA would also be required whenever a flow monitor is re-linearized (i.e., when its polynomial coefficients are changed). EPA is proposing to reduce the required frequency of 3-load RATAs and to allow limited use of single-load flow RATA testing principally because of the added assurance of data quality that will be provided by the proposed quarterly flow-to-load test.

3. Flow Monitor Bias Adjustment Factors

Today's rulemaking proposes to change the method of determining the bias adjustment factor for multiple-load flow RATAs. For 2-load RATAs (which would be done at the two most frequently used load levels as identified in proposed section 6.5.2.1 of Appendix A), the bias test would be done at the load level (or levels) designated as normal. If the monitor were to fail the bias test at any load level designated as normal, a bias adjustment factor (BAF) would be calculated at both load levels, and the higher of the two BAFs would then be applied to the subsequent flow data. For 3-load RATAs, the bias test would be required at each load level designated as normal under proposed section 6.5.2.1 of Appendix A. If the bias test were failed at any load level designated as normal, BAFs would be calculated only at the two most frequently used load levels (not all three

levels), and the higher of the two BAFs would be applied to subsequent flow data. Thus, for all multiple-load flow RATAs, the appropriate BAF would be determined in the same way. For 3-load RATAs, this methodology for determining the BAF when the normal-load bias test is failed differs from the current rule, which requires the highest BAF from any of the three levels to be applied to subsequent data. Experience gained in the first few years of program implementation has shown that in many instances, the highest BAF has been from a load level that is seldom used (generally the low load level), which can result in an unrepresentatively high BAF being applied to the normal-load flow rate data.

4. Number of RATA Attempts

Section 2.3.1.4 of Appendix B to today's proposed rule would remove the restriction limiting to two the number of RATA attempts that may be done to achieve an annual RATA frequency. In addition, the requirement that successive RATAs be conducted no less than 4 months apart would be removed from section 2.3.1 of Appendix B. The proposed rule would conditionally allow the owner or operator to perform as many RATAs as are necessary to achieve a better relative accuracy percentage or a more favorable bias adjustment factor, the condition being that the data validation procedures for RATAs in proposed section 2.3.2 of Appendix B would have to be followed (these procedures are discussed in detail in Section II.O of this preamble, ''CEM Data Validation''). The Agency believes that this extra flexibility will provide an incentive for owners or operators to optimize CEMS performance and to eliminate bias from their monitoring systems and to reduce the frequency of the required RATAs.

5. Concurrent SO_2 and Flow RATAs

Today's proposed rulemaking would delete the requirement for concurrent SO_2 and flow RATA testing from § 6.5 of Appendix A. This requirement was included in the January 11, 1993 rule in order to generate a data base from which EPA could determine the appropriateness of setting a combined flow rate-SO_2 system relative accuracy specification. Section 3.3.5 of Appendix A was reserved for this future standard, which, if promulgated, would have become effective on January 1, 2000. After three years of program implementation, data collection, and evaluation, however, the Agency believes it is not appropriate or necessary to propose a combined flow rate-SO_2 system relative accuracy standard. Instead, EPA believes it would be more appropriate to retain the individual relative accuracy specifications for the SO_2 and flow monitors. Because the historical relative accuracy percentages of the individual component monitors have proven to be so low (i.e., average relative accuracy less than 5.0 percent for the period from the first quarter of 1995 through the second quarter of 1996), the Agency believes that it is not necessary to promulgate the combined standard (see Docket A–97–35, Item II–I–27). Data analysis from an EPA study (see Docket A–97–35, Item II–I–14) indicates that quality assuring the individual component monitors to 7.5 percent relative accuracy (the RA value needed to qualify for an annual RATA frequency) effectively ensures that a combined flow rate-SO_2 standard of 10.0 to 15.0 percent relative accuracy will be consistently achieved. That same study also indicates that meeting a combined flow rate-SO_2 standard of 10.0 percent does not necessarily ensure that the individual component monitor relative accuracies will be ≤ 10.0 percent. In view of this and given that flow monitors are also used to calculate heat input and CO_2 mass emissions, the Agency believes it is appropriate to maintain individual relative accuracy standards for the flow monitor and SO_2 monitor. EPA solicits comment on its proposed treatment of this issue.

6. SO_2 RATA Exemptions and Reduced Requirements

Today's proposed rulemaking would clarify the RATA requirements for units that burn principally natural gas and other very low-sulfur fuels. In § 75.21(a)(6) of the November 20, 1996 rule, an exemption from SO_2 RATA requirements was provided for units that have SO_2 monitors and exclusively burn natural gas (or fuels with a sulfur content no greater than natural gas). Today's proposed rule would clarify this exemption from SO_2 RATAs by interpreting the term ''fuel with a total sulfur content no greater than the total sulfur content of natural gas'' to mean any type of fuel that has a total sulfur content of less than or equal to 0.05 percent sulfur by weight. The rationale for this is as follows. In order to meet the definition of natural gas in § 72.2, the total sulfur content of the gas cannot exceed 20 grains/100 scf. When this sulfur content is converted to a weight percentage, it comes out slightly higher than 0.05 percent sulfur by weight (see Docket A–97–35, Item II–B–14). Consequently, for a unit that has an SO_2 monitor and for which the designated representative certifies that the unit burns only fuels (whether solid, liquid, or gaseous) with a total sulfur content of > 0.05 percent sulfur by weight, the SO_2 monitor would be exempted from the part 75 RATA requirements. The Agency takes comment on this approach and on whether 0.05 percent sulfur by weight is an appropriate applicability threshold for fuels other than natural gas.

Finally, § 75.21(a)(7) of today's rule proposes reduced RATA requirements for units with SO_2 monitors for which the designated representative certifies that the units burn fuel(s) with a total sulfur content greater than the total sulfur content of natural gas (e.g., distillate oil) only as emergency backup fuel(s) and/or for short-term testing. For such units, RATA testing of the SO_2 monitor would only be required if fuel with a total sulfur content greater than the total sulfur content of natural gas (i.e., > 0.05 percent sulfur by weight) is combusted for more than 480 hours in a calendar year. If the higher-sulfur fuel usage were to exceed 480 hours in a particular year, then an SO_2 RATA, conducted while burning the higher-sulfur fuel, would be required either by the end of the quarter in which the exceedance occurred or within a 720 unit operating hour grace period following that calendar quarter. In this instance, if the grace period were used, proposed section 2.3.3 in Appendix B would specify that it would begin with the first unit operating hour in which the higher-sulfur fuel is combusted in the unit, following the calendar quarter in which the annual usage of the higher-sulfur fuel exceeded 480 hours. The 480-hour criterion for maintaining an SO_2 RATA exemption is consistent with many state and local air permits which contain a similar exemption from particulate emission testing for gas-fired units that burn oil for only 400 to 500 hours per year (see Docket A–97–35, Item II–E–23). EPA believes that these provisions would effectively eliminate the need to start up a unit and/or to burn an infrequently used, uneconomical, and higher-emitting fuel solely for the purpose of performing a RATA of the SO_2 monitor.

7. QA Provisions for SO_2 Monitors, for Natural Gas Firing or Equivalent

In § 75.11(e) of the November 20, 1996 revisions to part 75, three SO_2 compliance options were promulgated for units with SO_2 CEMS during hours in which only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) is burned. One of the compliance options was to allow the use of an SO_2 monitoring system, subject to

certain restrictions and quality assurance provisions. The restrictions and QA provisions, which are found at §§ 75.11(e)(3)(i) through (iv), are as follows: (i) a calibration gas with a concentration of 0.0 percent of span must be used for daily calibration error tests of the CEMS; (ii) the response of the monitoring system to the 0.0 percent calibration gas must be adjusted to read exactly 0.0 ppm each time that a daily calibration error test is passed; (iii) any hourly average of less than 2.0 ppm recorded by the SO_2 monitor while fuel is being combusted in the unit(s) (including zero and negative averages) must be reported as a default value of 2.0 ppm; and (iv) if a unit combusts only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) and never combusts any other type of fuel, the SO_2 monitor span must be set to a value not exceeding 200.0 ppm. Compliance with conditions (i) through (iv) is required by January 1, 1999, except that conditions (i) and (ii) are always optional for units that combust natural gas only during unit startup.

The provisions in §§ 75.11(e)(3)(i) through (iv), as presently codified, apply only to the combustion of *gaseous* fuel with a total sulfur content no greater than the total sulfur content of natural gas. However, as noted above (under ''SO_2 RATA Exemptions and Reduced Requirements''), today's proposed rulemaking would add an interpretation of the term ''fuel with a total sulfur content no greater than the total sulfur content of natural gas'' to § 75.21(a)(6). The term would include *any* fuel (whether solid, liquid, or gaseous) with a total sulfur content of ≤ 0.05 percent by weight. EPA believes that it is appropriate to apply the quality assurance and reporting provisions in §§ 75.11(e)(3)(i) through (iv) to the combustion of *all* fuels with a total sulfur content ≤ 0.05 percent by weight. Therefore, in today's proposed rule, a new section, § 75.21(a)(8) would be added, extending the QA provisions of §§ 75.11(e)(3)(i) through (iv) to the combustion of all types of fuels with a total sulfur content no greater than the total sulfur content of natural gas. The new requirements would become effective on January 1, 2000.

Note that EPA has reconsidered one of the four QA provisions for the use of an SO_2 monitor during natural gas (or fuel with equivalent total sulfur content) combustion in §§ 75.11(e)(3)(i) through (iv). Specifically, the Agency believes that § 75.11(e)(3)(ii), which requires a daily adjustment of the monitor's calibration to read *exactly* 0.0 ppm, may be too stringent because in practice it can be very difficult to attain a reading of exactly 0.0 ppm with a zero-level calibration gas, particularly when manual calibration adjustments are made. Therefore, today's rulemaking proposes to revise § 75.11(e)(3)(ii) as follows. Rather than requiring a daily adjustment of the SO_2 monitor's calibration, an adjustment would only be required when the ''as-found'' response of the monitor to the zero gas during a daily calibration error test exceeded the performance specification of the instrument (i.e., ±2.5 percent of span). And instead of requiring the calibration to be adjusted to exactly 0.0 ppm, the procedures for routine calibration adjustments in proposed section 2.1.3 of Appendix B would be followed, to bring the ''as-left'' response of the instrument (i.e., the response during the additional calibration error test required by proposed section 2.1.3 of Appendix B) ''as close as practicable'' to the true value of the zero gas (0.0 ppm).

The Agency solicits comment on the proposed approach for QA provisions for SO_2 CEMS for gas-firing or equivalent.

8. General RATA Test Procedures

Under today's proposal, sections 6.5, 6.5.1, and 6.5.2 of Appendix A, which describe the general requirements for RATAs, would be extensively revised. Some of the proposed changes are simply structural, but others are substantive. For instance, as previously discussed above under ''Concurrent SO_2 and Flow RATAs,'' the requirement to perform concurrent SO_2 and flow RATAs would be deleted from the regulation. Further, section 6.5 would now recognize that more than one type of fuel and more than one monitor range may be considered normal for a particular unit. Also, the requirement to complete each RATA within 7 consecutive calendar days would be modified to require that the RATA be completed within 168 unit operating hours (for single-load flow RATAs and, to the extent practicable, for 2-load and 3-load flow RATAs). However, for the multiple-load flow RATAs, up to 720 unit operating hours would be allowed, if necessary, to complete the testing. This is consistent with Agency guidance published in March, 1995, Policy Question 8.15 of the Acid Rain Policy Manual, which discusses allowing up to 30 calendar days to complete all three levels of a 3-load flow RATA (see Docket A–97–35, Item II–I–9). Even though the policy says the RATAs at the individual load levels should be completed within 7 days, thirty days are acceptable to complete the 3-load RATA in order to account for the possibility that the unit might shut down in between levels of the RATA or that certain load levels may be difficult to attain and to hold. Today's proposal would allow 720 unit operating hours (irrespective of the number of calendar days) to complete a multiple-load flow RATA. EPA believes that this proposed requirement provides greater flexibility than currently allowed.

Sections 6.5.1 and 6.5.2 of Appendix A would be re-titled ''Gas Monitoring Systems (Special Considerations)'' and ''Flow Monitor RATAs (Special Considerations),'' respectively. Proposed section 6.5.1 contains a recommendation that, for initial monitor certifications, the RATA not be commenced until all of the other certification tests have been completed. Section 6.5.2 would be amended, as previously discussed under ''Flow RATA Load Levels.'' The definition of normal load would be revised and the number of loads and the load levels at which flow RATAs are to be performed would be more clearly defined.

Today's rule proposes changes to section 6.5.6 of Appendix A, which pertains to RATA traverse point selection. Proposed section 6.5.6 would allow the following alternative reference method measurement point locations. For *all* moisture determinations, a single reference method point, located at least 1.0 meter from the stack wall, could be used. For gas RATAs, the owner or operator would have four options: (1) at *any* location (including locations where stratification is expected), a minimum of six traverse points along a diameter, located in accordance with Method 1 in Appendix A to part 60, could be used; (2) at locations where stratification is not expected and section 3.2 of Performance Specification No. 2 (''PS No. 2'') in Appendix B to part 60 allows the use of a short reference method measurement line (with three points located at 0.4, 1.0, and 2.0 meters from the stack wall), the owner or operator could use an alternative 3-point measurement line, locating the three points 4.4 percent, 14.6 percent and 29.6 percent of the way across the stack, in accordance with Method 1 in Appendix A to part 60; (3) at locations where stratification is expected (i.e., after a wet scrubber or when dissimilar gas streams are combined), the short measurement line from section 3.2 of PS No. 2 (or the alternative line described in option (2) above) could be used in lieu of the ''long'' measurement line prescribed in section 3.2 of PS No. 2, provided that a stratification test is performed prior to each RATA at the location and certain acceptance criteria

are met; and (4) a single reference method measurement point, located no less than 1.0 meter from the stack wall, could be used at *any* test location if a stratification test is performed prior to each RATA at the location and certain acceptance criteria are met. EPA's Office of Air Quality Planning and Standards (OAQPS) has endorsed the use of the Method 1 traverse points as an alternative to the points prescribed by PS No. 2 (see Docket A–97–35, Item II–C–22).

Regarding option (3) above, one utility and one stack testing firm have requested that EPA allow the short measurement line to be used at scrubbed unit stacks, citing logistical difficulties and safety concerns associated with using the long measurement line prescribed by PS No. 2 for sampling locations following wet scrubbers (see Docket A–97–35, Items II–D–66, II–D–78). Both parties appeared willing to perform stratification testing to demonstrate that the gas streams are not significantly stratified. EPA responded to these requests by issuing policy guidance which discusses allowing the short measurement line to be used for scrubbed units, provided that stratification test results show the stratification at the sampling location to be minimal (see Docket A–97–35, Item II–I–9, Policy Manual, Question 8.25). Regarding single-point RATA testing (option (4), above), which utility groups asked EPA to consider, today's proposed rule would allow it on the condition that a stratification test at the sampling location demonstrates stratification to be essentially absent.

Sections 6.5.6.1 and 6.5.6.2 of Appendix A in today's proposed rule provide two stratification test protocols which may be used to demonstrate that a sampling location qualifies for the alternative RM measurement point locations allowed under proposed section 6.5.6 (i.e., options (3) and (4), above). The first stratification test protocol, in proposed section 6.5.6.1, is based upon technical guidance issued by OAQPS (see Docket A–97–35, Item II–I–3) and would consist of measuring the SO_2, NO_X, and diluent gas concentrations at a minimum of 12 traverse points, located in accordance with Method 1 in Appendix A to part 60. The gas concentration measurements would be made using Reference Methods 6C, 7E, and 3A in Appendix A to part 60. The average NO_X, SO_2, and CO_2 (or O_2) concentration at each of the individual traverse points would be determined, and the arithmetic average NO_X, SO_2, and CO_2 (or O_2) concentrations for all traverse points calculated. This 12-point test would have to be passed one time at the sampling location under consideration. Once the 12-point test has been passed at the candidate sampling location, the second (abbreviated) stratification test protocol, in proposed section 6.5.6.2, could be done prior to subsequent RATAs at the location in lieu of the 12-point test. The abbreviated test would be done either at 3 points (located in accordance with the long measurement line in PS No. 2) or at 6 points along a diameter (located according to EPA Method 1 in Appendix A to part 60).

The acceptance criteria for the stratification test results are given in proposed section 6.5.6.3 of Appendix A. For each pollutant or diluent gas, the short 3-point reference method measurement line specified in section 3.2 of PS No. 2 (or the alternative 3-point line described in proposed section 6.5.6 of Appendix A) could be used for that pollutant or diluent gas in lieu of the long measurement line in section 3.2 of PS No. 2, if the concentration at each individual traverse point differed by no more than ±10.0 percent from the arithmetic average concentration for all traverse points. The results would also be acceptable if the concentration at each individual traverse point differed by no more than ±5.0 ppm or 0.5 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points. Further, for each pollutant or diluent gas, a single reference method measurement point located at least 1.0 meter from the stack wall could be used for that pollutant or diluent gas, if the concentration at each individual traverse point differed by no more than ±5.0 percent from the arithmetic average concentration for all traverse points. The results would also be acceptable if the concentration at each individual traverse point differed by no more than ±3.0 ppm or 0.3 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points. Finally, proposed section 6.5.6.3 would require the owner or operator to keep the results of all stratification tests on-site, suitable for inspection, as part of the supplementary RATA records required under § 75.56(a)(7) and § 75.59(a)(7).

Today's rule also proposes to clarify the sampling strategy for RATAs in section 6.5.7 of Appendix A. The proposed revisions make it clear that for gas monitor RATAs, the minimum time per run is 21 minutes, and all of the necessary data for each run (i.e., pollutant concentration measurements and, if applicable, diluent concentration data and moisture measurements) would have to be collected, to the extent practicable, within a 60-minute period. The proposed revisions would also require the pollutant and diluent concentration measurements to be made simultaneously during RATAs of SO_2/diluent and NO_X/diluent monitoring systems. For flow monitor RATAs, the minimum time per run would be 5 minutes. A requirement to properly account for flow pulsations (e.g., by sight-weighted averaging) at each velocity traverse point would be added, as well as a clear statement that successive flow RATA runs may be done as rapidly as practicable, with no required waiting period between runs. Proposed section 6.5.7 of Appendix A states that a minimum of one set of auxiliary data (moisture and diluent gas measurements) would have to be collected for every three RATA runs or for every clock hour of a flow RATA (whichever is less restrictive). A related change to § 75.22(a)(4) is also proposed, which would allow the alternative moisture measurement techniques described in section 1.2 of Method 4 in Appendix A to part 60 to be used for stack gas molecular weight determinations.

9. Reference Method Testing Issues

Discussion of Proposed Changes

Currently, § 75.22 specifies several reference methods (Reference Methods 2, 2A, 2C, or 2D) as appropriate methods for determining volumetric flow under part 75. The Agency is currently conducting a study of the accuracy of Reference Method 2 to determine whether changes to Method 2 or the addition of other alternatives to the Method are appropriate. Thus, the Agency anticipates that, in the future, revisions to Method 2 in part 60 may create alternatives beyond the specific reference methods specified in § 75.22(a)(2). Therefore, in § 75.22(a)(2), EPA proposes to add: ''or its allowable alternatives, except for 2B and 2E'' to Method 2 to automatically incorporate into part 75 anticipated future revisions to the Method 2 requirements in Appendix A to part 60.

Section 75.22 specifies a number of instrumental reference methods from Appendix A to part 60 (Reference Methods 3A, 6C, 7E, and 20) as appropriate test methods for conducting CEMS performance tests under part 75. These methods require the use of calibration gases to calibrate the reference analyzers. Currently, however, part 60 does not require that EPA protocol gas be used when performing instrumental reference methods. The Agency believes that protocol gas should be used when performing instrumental reference methods in order

to achieve accurate results. Therefore, proposed § 75.22(c)(1) would state that, for purposes of part 75, instrumental reference methods must be performed using calibration gases as defined in section 5 of Appendix A to part 75.

10. Alternative Relative Accuracy Specifications and Specifications for Low-Emitters

One utility group has suggested to EPA (see Docket A–97–35, Item II–E–13) that there is inconsistency and apparent inequity in the relative accuracy specifications for units that qualify as low emitters of NO_X and SO_2 (i.e., sources with average SO_2 concentrations of 250.0 ppm or less and/or average NO_X emission rates of 0.20 lb/mmBtu or less). Specifically, they have questioned the appropriateness of the alternative relative accuracy specifications used to determine the RATA frequency (i.e., semiannual or annual). Under section 3.3 of Appendix A and section 2.3.1 of Appendix B to the current part 75 rule, the RATA frequency for an SO_2 monitor installed on a low-emitting SO_2 source may be determined in either of two ways: by the normal relative accuracy specification (i.e. the RATA frequency is semiannual if the relative accuracy is > 7.5 percent but ≤ 10.0 percent, and annual if ≤ 7.5 percent relative accuracy is achieved), or by the alternative specification (i.e., the RATA frequency is semiannual if the reference method mean value and CEMS mean value differ by > 8.0 ppm but ≤ 15.0 ppm, and annual if the two mean values differ by ≤ 8.0 ppm). For low-emitting NO_X sources, the RATA frequency for the NO_X monitoring system is determined in the identical manner to SO_2 when the normal specification is applied. For the alternative specification, the NO_X RATA frequency is semiannual if the CEMS and reference method mean values differ by ≤ 0.01 lb/mmBtu but ≤ 0.02 lb/mmBtu, and annual if the mean values differ by > 0.01 lb/mmBtu. The 8.0 ppm value for SO_2 was originally determined based on the performance of a single set of monitors at a facility regulated under subpart Da of the NSPS in part 60. However, in the first few years of Acid Rain Program implementation, many part 75 utilities with wet scrubbers have found it difficult to consistently meet the 8.0 ppm criterion for obtaining an annual RATA frequency.

The utility group maintains that since, when the normal relative accuracy (RA) specification is applied, the criterion for obtaining an annual RATA frequency is to achieve a relative accuracy 25.0 percent below the RA specification in section 3.3 of Appendix A (i.e., 7.5 percent RA is 25.0 percent below the specification of 10.0 percent), the criterion for an annual RATA frequency should be essentially the same when the alternative specification is applied. Under the current rule, the alternative SO_2 specification requires that the mean CEMS and reference method values differ by no more than 8.0 ppm in order to obtain an annual RATA frequency. This is 47.0 percent below the 15.0 ppm alternative RA specification. Similarly for NO_X, the alternative NO_X specification for an annual RATA frequency requires the difference between the CEMS and reference method mean values to be ≤ 0.01 lb/mmBtu, or 50.0 percent below the 0.02 lb/mmBtu alternative RA specification.

EPA agrees that the alternate RA specifications for low emitters of SO_2 and NO_X appear to be somewhat inequitable, and today's rulemaking proposes changes to these specifications. In proposed section 2.3.1 of Appendix B, the alternative relative accuracy specification for low emitters of SO_2, (i.e., the difference between the reference method and CEMS mean values) that must be met by an SO_2 monitor in order to obtain an annual RATA frequency would be changed from 8.0 ppm to 12.0 ppm. For low emitters of NO_X, the alternative low emitter relative accuracy specification that must be met by a NO_X-diluent monitoring system in order to obtain an annual RATA frequency would be changed from 0.01 lb/mmBtu to 0.015 lb/mmBtu.

In today's rule, EPA is also proposing an alternative relative accuracy specification of 0.025 lb/mmBtu for SO_2-diluent monitoring systems to obtain an annual RATA frequency and an alternative relative accuracy specification of ±0.7 percent CO_2 or O_2, by which CO_2 and O_2 monitors could obtain an annual RATA frequency. During the investigation of the alternative RA specifications for the SO_2 and NO_X-diluent monitoring systems, the Agency noted that for SO_2-diluent systems, part 75 specifies only an alternative RA criterion of 0.030 lb/mmBtu for a semiannual RATA frequency, but fails to specify a corresponding alternative RA criterion for obtaining an annual RATA frequency. Similarly, for CO_2 and O_2 monitors, EPA noted that an alternative relative accuracy specification of ±1.0 percent CO_2 or O_2 (in terms of the mean difference between the reference method and CEM values during the RATA) is given for obtaining a semiannual RATA frequency, but no corresponding alternative criterion is given for obtaining an annual frequency.

EPA notes that in order to make the annual RATA frequency criteria for NO_X-diluent and SO_2-diluent monitoring systems more equitable, a third decimal place is required. However, §§ 75.54 and 75.55 currently require NO_X and SO_2 emission rates in lb/mmBtu to be reported only to 2 decimal places. Therefore, revisions are being proposed, see §§ 75.57(d)(6) and 75.58(a)(1)(iv), to require that, beginning on January 1, 2000, all NO_X emission rates in lb/mmBtu must be reported to three decimal places. Prior to January 1, 2000, the owner or operator would have the option of reporting NO_X emission rates to either two or three decimal places. Note that no corresponding change is being proposed for the reporting of SO_2 emission rates in lb/mmBtu, since such emission rates will only be reported to EPA by units that have installed Phase I Qualifying Technologies for a three-year period (1997–1999), and are not required to be reported thereafter. EPA solicits comments on the appropriateness of requiring *all* NO_X lb/mmBtu emission rates to be reported to three decimal places. The Agency favors this approach, particularly for quality assurance purposes, due to increased precision in the calculation of RATA results. The Agency notes that this proposed change would not affect the way in which compliance with the NO_X emission limits under part 76 is determined. Compliance with part 76 NO_X limits, in lb/mmBtu, would still be based on two decimal places.

All of the proposed revisions to the part 75 relative accuracy specifications in today's rulemaking are summarized in proposed Figure 2 of Appendix B.

11. *Bias Adjustment Factors for Low Emitters*

As discussed in the preceding section, sources that qualify as low emitters of SO_2 and/or NO_X have two ways to evaluate the relative accuracy of SO_2 and NO_X monitoring systems: (a) by the normal relative accuracy specification (i.e., 10.0 percent RA), and (b) by the alternative RA specification (i.e., the difference between the mean CEMS and reference method values is within ±15.0 ppm for SO_2 low emitters, or within ±0.02 lb/mmBtu for NO_X low emitters).

The normal RA is determined by a statistical analysis of the reference method and CEMS data from the RATA. Mathematically, the normal RA is the sum of the absolute values of the mean difference (d_{mean}) and the confidence coefficient (cc), expressed as a percentage of the mean reference method value $(RM)_{avg}$. The mean difference indicates how closely the CEMS measurements agree with the

reference method and is generally the principal contributor to the percentage relative accuracy in the RA equation. The confidence coefficient (cc) is a statistical term related to the standard deviation and is an indicator of the amount of scatter in the data.

Section 7.6 of Appendix A requires a bias test of each SO_2 and NO_X monitoring system whenever a RATA of the CEMS is performed. If the mean difference is greater than the absolute value of the confidence coefficient, the CEMS measurements are systematically lower than the corresponding references method measurements, i.e., the monitoring system has a low bias. In such cases, sources are given two options. The first, preferred by EPA, is to locate and eliminate the source of the measurement bias in the instrument. The second option is to apply a bias adjustment factor (BAF). This alternative was developed in response to an industry request to provide an alternative for sources that choose not to expend the effort to locate and eliminate the technical problem causing the systematic measurement error. The BAF is equal to $1.000 + |d_{mean}| / (CEM)_{avg}$, where $(CEM)_{avg}$ is the mean value of the CEMS measurements from the RATA.

At least one utility has questioned whether it is appropriate for low emitters to calculate a BAF in the usual way when a CEMS fails a RATA by the normal RA specification, but passes by the alternative specification, because in such cases the BAF can become inordinately high, particularly at very low emission levels (see Docket A–97–35, Items II–D–62 and II–E–23). Since both the percent relative accuracy and the BAF are based upon the same statistical terms (d_{mean} and cc), the utility questions whether the standard calculation procedure for the BAF is adequate to determine a meaningful BAF for low emitters. Just as the value obtained from the standard relative accuracy equation tends to become large for low emitters, so, too, the BAF is seen as becoming inordinately large for low emitters which use the current BAF equation.

As this comment suggests, it is not uncommon for an SO_2 or NO_X CEMS installed on a low-emitting unit to fail a RATA by the normal specification of 10.0 percent RA and to pass the same RATA by the alternative RA specification. For instance, suppose that the mean RM and CEMS values during an SO_2 RATA of a low emitter are 51.0 ppm and 40.0 ppm, respectively, and that d_{mean} is 11.0 ppm and the confidence coefficient is 0.50. Suppose further that the bias test is failed. Then, the percent RA by the normal specification (i.e., $|d_{mean}| + |cc| / (RM)_{avg}$) would exceed 20.0 percent, indicating a failed RATA, but the alternative RA specification would indicate a pass (i.e., $(CEMS)_{avg}$ is within ±15.0 ppm of $(RM)_{avg}$). In this same illustration, the BAF would be 1 + 11 / 40 = 1.275.

In fact, if it is assumed that the difference between the CEMS and the reference method measurements does not decrease as emissions decline, then the lower the SO_2 or NO_X emissions, the more likely it is for the CEMS to fail the normal relative accuracy specification because the mean difference becomes a larger percentage of the average reference method value. It was precisely in response to such concerns that the alternative relative accuracy specifications were originally included in part 75.

Today's rule proposes to provide an option in the way the BAF is determined for low emitters of SO_2 and NO_X. Low emitters of SO_2 and NO_X would be given the choice of using either: (a) the normal BAF calculation procedure described above and found in Equation A–12, section 7.6.5 of Appendix A, or (b) an alternative default bias adjustment factor of 1.111.

The justification is as follows: for units that meet the normal relative accuracy standard of RA ≤ 10.0 percent, the theoretically maximum possible Bias Adjustment Factor is 1.111 (see Docket A–97–35, Item II–B–2). Therefore, low-emitting units meeting the alternative relative accuracy standards ($|d_{mean}| \leq 15.0$ ppm for SO_2 low emitters and $|d_{mean}| \leq 0.02$ lb/mmBtu for NO_X low emitters) should not have to apply a bias adjustment any higher than the maximum BAF value applicable to units meeting the normal relative accuracy standard. EPA solicits comment on allowing the alternative BAF of 1.111 for low-emitting units.

12. Clarification of Diluent Monitor Certification Requirements

Today's proposed rule would clarify the certification requirements for diluent gas (CO_2 and O_2) monitors, in response to comments received on the pre-proposal draft of the rule (see Docket A–97–35, Item II–D–52). Section 75.20(c)(1)(iii) of the current rule requires a RATA of each NO_X continuous monitoring system to be done for initial certification. Even though the NO_X system consists of two component monitors (NO_X concentration and diluent gas), the required RATA is done on a system basis in units of lb/mmBtu. Separate RATAs of the individual component monitors are not required, except when the diluent component monitor is also used as a CO_2 pollutant concentration monitor or to account for unit heat input, in which case § 75.20(c)(5)(iii) in the current rule requires a RATA of the diluent monitor. To be sure that this is clear, today's proposed rule would add a statement to § 75.20(c)(1)(iii), indicating that the RATA for the NO_X-diluent system shall be done on a system basis (i.e., individual component RATAs are unnecessary for certification of a NO_X-diluent system). Therefore, units that have installed NO_X monitoring systems, but that use Appendix D for SO_2 emission accounting and Appendix G for CO_2 accounting, would not be required to submit separate RATA results for the diluent monitor.

A second point of clarification would be added in proposed § 75.20(c)(3), which was previously designated as § 75.20(c)(4). The new section would make it clear that when a diluent monitor (O_2 or CO_2) is used both as a CO_2 pollutant concentration monitor and for heat input determinations, only one set of diluent monitor certification test results would have to be submitted under the component and system ID codes of the CO_2 monitoring system. This is appropriate because there is no such thing as a ''heat input monitoring system'' or an ''oxygen monitoring system'' under part 75.

13. Daily Calibration Requirements for Redundant Backup Monitors

Section 75.20(d)(1) of the current rule requires redundant backup (''hot-standby'') monitoring systems to be operated during all periods of unit operation and to meet all of the quality assurance requirements of Appendix B, including daily calibrations and interference checks, quarterly linearity checks and leak checks, and semiannual or annual RATAs. One commenter on a pre-proposal draft of today's proposed rule requested that EPA consider changing the daily calibration requirement for redundant backup monitors (see Docket A–97–35, Item II–D–35). The commenter recommended that the daily calibrations be made mandatory only for days on which the redundant backup monitoring system is actually used to report emission data to EPA. Daily calibrations would be optional on all other days. Fewer calibrations of redundant backup systems would considerably reduce calibration gas consumption. The commenter estimated that this change could result in an annual savings of more than $100,000 for his company. EPA agrees that the request is reasonable, provided that the redundant

backup systems are kept on hot-standby and are calibrated prior to each use for reporting. The Agency therefore proposes to amend § 75.20(d)(1) accordingly.

14. Daily Performance Specification and Control Limits for Low-Span DP Flow Monitors

Section 3.1 of Appendix A of the current rule gives the calibration error performance specification for flow monitors. Section 2.1.4 of Appendix B gives the calibration error limits for daily operation of flow monitors. For initial certification, a flow monitor is required to meet a calibration error specification of ≤ 3.0 percent of the span value. For daily operation of the flow monitor, the calibration error must not exceed 6.0 percent of span. These specifications are both reasonable and achievable for the vast majority of flow monitors. However, when a differential pressure (DP) type flow monitor is used to measure stack gas flow rate in a stack that has low exit velocities, it can be very difficult for the monitor to pass its daily calibration error tests. This is because the daily calibration span value for a DP flow monitor is expressed in units of inches of water. For stack exit velocities less than 2000 feet per minute, the calibration span value will be a very small number (0.20 inches of water or less). When performing a daily calibration error test of a flow monitor with a span value of 0.20 inches of water, the test would be failed (i.e., the calibration error would exceed 6.0 percent of span) if the response of the monitor deviated from either the zero or high reference signal by 0.02 inches of water. For span values of 0.15 inches of water or less, the calibration error test would be failed if the monitor's response deviated from the reference signals by 0.01 inches of water. One utility with a DP type flow monitor with a span value less than 0.15 inches of water has indicated to EPA that it cannot pass daily calibrations unless the monitor responses exactly equal the reference signal values (see Docket A–97–35, Item II–E–30). Clearly, these daily calibration specifications are too stringent for low span DP-type flow monitors. In view of this, EPA is proposing alternative calibration error specifications for DP type flow monitors with low span values, with ''low'' span value meaning a span value of 0.20 inches of water or less. The alternative performance specification for initial certification, given in proposed section 3.1 of Appendix A, would be ± 0.01 inches of water, rather than ± 3.0 percent of span. The alternative specification for daily operation of the monitor, given in proposed section 2.1.4 of Appendix B, would be ± 0.02 inches of water, rather than ± 6.0 percent of span. Since the results of a calibration error test of a DP type flow monitor are reported to 2 decimal places, the performance specification of ± 0.01 inches of water, is the tightest specification that could be imposed, short of requiring the monitor to read exactly the reference value with zero tolerance (which is what the current specification of ± 3.0 percent of span essentially imposes on a DP flow monitor with very low span). The Agency solicits comment on this proposed approach and on the value of the alternate specification.

O. CEM Data Validation

Background

The current requirements of part 75 regarding CEM data validation are as follows. Section 75.10 specifies that a valid hourly average from a CEMS must be based on a minimum of four evenly spaced data points (i.e., one point in each 15-minute quadrant of the clock hour), except that two evenly spaced data points separated by at least 15 minutes are sufficient to validate an hourly average when daily calibration error tests and/or other required quality assurance activities are conducted during the hour. Data from a CEMS are considered to be quality assured, provided that the monitoring system has passed all of the initial certification tests required under § 75.20(c) and provided that the CEMS is not ''out-of-control,'' as a result of having failed any of the daily, quarterly, semiannual, and/or annual quality assurance tests required in sections 2.1 through 2.3 of Appendix B. Out-of-control periods extend from the hour of failure of a QA test until the hour of completion of a subsequent successful QA test of the same type. For instance, if a linearity check of a gas monitor is failed, the monitor is considered out-of-control from the hour of completion of the failed test until the hour of completion of a subsequent successful linearity test.

Finally, § 75.20(b)(3) specifies that when a change is made to a CEMS such that recertification of a monitor becomes necessary, data from the CEMS are invalid from the hour in which the change is made to the system until the hour of completion of all required recertification tests.

In the first three years of implementing part 75, EPA has received numerous requests from the utilities for guidance concerning CEM data validation. This has prompted the Agency to re-examine these provisions of the rule. From this re-examination, the Agency believes that the current data validation provisions of part 75 are neither sufficiently detailed nor flexible to address the complex realities of daily operation of utility boilers and continuous emission monitoring systems. Therefore, today's proposed rule would set forth more comprehensive data validation criteria.

Discussion of Proposed Changes

Today's proposed rule would set forth proposed guidelines for the validation of CEM data, attempting to take into account the realities associated with the operation and maintenance of electric utility steam generating units and continuous emission monitoring systems. The proposed guidelines would govern CEM data validation as it pertains to six principal areas: (1) calibration error tests and adjustment of gas and flow monitors; (2) linearity tests of gas monitors; (3) relative accuracy test audits of gas and flow monitoring systems; (4) recertifications of gas or flow monitors; (5) data from non-redundant backup monitoring systems; and (6) missed QA test deadlines. These proposed guidelines for data validation are discussed in detail below.

1. Recalibration and Adjustment of CEMS

Today's proposed rule would revise section 2.1.3 of Appendix B, the ''recalibration'' section. The May 17, 1995 rule recommends (but does not require) the calibration of a monitor to be adjusted whenever the daily calibration error exceeds the performance specification in Appendix A. For example, if the calibration error of a gas monitor exceeds 2.5 percent of span, but does not exceed the daily control limit of 5.0 percent of span, the monitor is considered to be out-of-adjustment but not out-of-control, and EPA recommends that calibration of the monitor be adjusted.

Today's proposal would re-title section 2.1.3 as ''Additional Calibration Error Tests and Calibration Adjustments.'' The recommendation to adjust the monitor when the calibration error exceeds the Appendix A performance specification would be retained, but definitions of ''routine calibration adjustments'' and ''non-routine calibration adjustments'' would be added. Routine calibration adjustments would be defined as adjustments made to a CEMS following a successful calibration error test. The purpose of these adjustments would be to bring the monitor readings as close as practicable to the tag values of the reference calibration gases or to the

known values of the flow monitor reference signals. Non-routine calibration adjustments would be adjustments in either direction (toward or away from the reference value), but within the performance specifications of the monitor (i.e., within ± 2.5 percent of span for an SO_2 or NO_X monitor, ± 0.5 percent CO_2 or O_2 for a diluent monitor, or ± 3.0 percent of span for a flow monitor). Non-routine calibration adjustments would be permitted, provided that an acceptable technical justification is included in the QA/QC program required under section 1 of Appendix B. An additional calibration error test would be required following non-routine adjustments, to demonstrate that the instrument is still operating within its performance specifications.

In addition to the daily calibration error requirements in section 2.1.1 of Appendix B, today's proposed rule would require a calibration error test in four specific instances: (1) whenever a daily calibration error test is failed; (2) when a CEMS is returned to service following routine or corrective maintenance that may affect the ability of the CEMS to accurately measure and record emissions data; (3) following routine calibration adjustments in which the monitor's calibration is physically adjusted, e.g., by means of a potentiometer (however, an additional calibration error test would not be required if a mathematical algorithm in the DAHS is used to make the routine adjustments); and (4) following non-routine calibration adjustments. Data from the CEMS would be considered invalid until the required additional calibration error test had been successfully completed.

EPA is proposing to allow non-routine calibration adjustments within the performance specifications of an instrument for two principal reasons. First, commenters have expressed concern that restricting allowable adjustments to routine calibration adjustments would limit their ability to make adjustments within the acceptable plus or minus control limits of a monitor, particularly prior to linearity tests and RATAs. They have indicated that this flexibility is necessary because the tag values of reference gases are not 100.0 percent accurate and adjustments of the analyzer may be needed to account for these inaccuracies (see Docket A–97-35, Item II–I–15). EPA agrees that this is a legitimate concern. Because there is a tolerance of ± 2.0 percent on the different reference gases used for daily calibration error tests, linearity tests, and RATAs, it may be necessary to adjust toward or away from the tag value in order to make sure that the test specifications are met. The Agency believes, however, that it is appropriate to limit the calibration adjustments to within the instrument's performance specifications (i.e., ± 2.5 percent of span (for SO_2 and NO_X), ± 3.0 percent of span (for flow rate), and ± 0.5 percent CO_2 or O_2) in order to provide an on-going demonstration that the CEMS can simultaneously comply with the applicable daily, quarterly, semiannual, or annual performance specifications in Appendix A. One utility has expressed concern about its vendor's practice of making large calibration adjustments to the CO_2 monitor prior to RATA testing (see Docket A–97–35, Item II–D–63).

The second reason for proposing to allow non-routine calibration adjustments is the sensitivity of dilution-extractive monitors to changes in barometric pressure, temperature, and molecular weight. EPA believes that the best way to deal with this deficiency in the dilution-extractive monitoring technology is to develop a mathematical algorithm (site-specific, if necessary) that continuously applies a correction to the measurement in order to compensate for pressure, temperature, and molecular weight, as necessary, and to program the algorithm into the DAHS. However, in commenting on a pre-proposal draft of today's proposed rule, a number of utilities indicated that they prefer to account for dilution probe pressure effects by manually adjusting the monitor's calibration in anticipation of barometric pressure changes (e.g., approaching weather fronts) (see Docket A–97–35, Items II–D–41, II–D–55). After much deliberation, the Agency is proposing to allow such adjustments, provided that: (1) the calibration of the monitor is not adjusted outside of its performance specifications; (2) an additional calibration error test is done to verify that the adjustments have been properly made; and (3) the procedures used for the adjustments are included in the QA/QC program for the CEMS. Despite this, EPA still prefers that automatic pressure, temperature, and molecular weight compensation be used, where necessary, and would strongly encourage all facilities with dilution-extractive monitors to develop and apply the necessary mathematical algorithm(s).

2. Linearity Tests

Today's proposal would provide rules for data validation during linearity tests, in proposed section 2.2.3 of Appendix B. A routine quality assurance linearity test could not be commenced if the CEMS were operating ''out-of-control'' with respect to any of its other daily, semiannual, or annual quality assurance tests. Linearity tests would be done ''hands-off,'' as follows. Prior to the test, both routine and non-routine calibration adjustments, as defined in proposed section 2.1.3 of Appendix B, would be permitted. During the linearity test period, however, no adjustment of the monitor would be permitted except for routine daily calibration adjustments following successful daily calibration error tests (the Agency notes that it is unlikely for calibration error tests to be done during a linearity test period except when two or more operating days are required to complete the test, e.g., for a peaking unit).

Proposed section 2.2.3 of Appendix B would specify that when a linearity check is failed or aborted due to a problem with the monitor, the monitor would be declared out-of-control as of the hour in which the test is failed or aborted. Data from the monitor would remain invalid until the hour of completion of a subsequent successful hands-off linearity test. This proposed requirement is not substantially different from the out-of-control provision in the current rule. It would merely extend the definition of out-of-control to include linearity tests that are aborted prior to completion due to a problem with the monitor. The underlying assumption is that the aborted linearity test would not have been passed if all nine gas injections had been completed. However, a linearity test that is aborted for a reason unrelated to a monitor malfunction (e.g., an unplanned or forced unit outage) would not trigger an out-of-control period.

Finally, a new section, 2.2.4, would be added to Appendix B, providing a linearity test grace period of 168 unit operating hours. The purpose of the grace period would be to give the owner or operator a window of opportunity in which to perform a linearity test, when either: (1) the required linearity test cannot be completed within the QA operating quarter in which it is due, or (2) four consecutive calendar quarters have elapsed since the end of the calendar quarter in which a linearity test of a monitor (or range) was last done. Data validation during a grace period would be done according to the applicable provisions of proposed section 2.2.3 of Appendix B. Proposed section 2.2.4 of Appendix B would specify that if the required linearity test has not been completed within the grace period, data from the monitor would become invalid, beginning with the first hour following the expiration of the grace period and would remain invalid until the hour of completion of a

subsequent successful, hands-off linearity test. Proposed section 2.2.4 would further specify that a linearity test done during a grace period could only be used to meet the linearity test requirement of a previous QA operating quarter, not the requirement of the quarter in which the grace period is used. Note that proposed sections 2.2.3 and 2.2.4 of Appendix B would also extend the 168 unit operating hour grace period to apply to the quarterly leak checks of differential pressure-type flow monitors.

3. RATAs

Today's proposal would provide rules for data validation during gas and flow monitor RATA tests, in section 2.3.2 of Appendix B. Proposed section 2.3.2 would specify that a routine quality assurance RATA could not be commenced if the monitoring system is out-of-control with respect to any of its daily quality assurance assessments, including the additional calibration error test requirements of proposed section 2.1.3 of Appendix B. All RATAs would be done ''hands-off,'' as follows. Prior to the RATA , both routine and non-routine calibration adjustments would be permitted, in accordance with proposed section 2.1.3 of Appendix B. During the RATA test period, however, only routine calibration adjustments (as defined in proposed section 2.1.3 of Appendix B) would be permitted. For 2-level and 3-level flow RATAs, no linearization of the monitor would be permitted between load levels.

Note that EPA is proposing to allow pre-RATA adjustments and linearization of a CEMS, principally to encourage facilities to optimize the performance of their CEMS by achieving the best possible relative accuracy results in a cost-effective manner with little or no data loss. The Agency believes that there is no significant risk in allowing pre-RATA adjustments, provided that the monitor's continued accuracy between successive RATAs can be reasonably established. For gas monitors, EPA believes that the daily calibration error tests and quarterly linearity tests, which challenge the analyzers with protocol gases of known concentration, provide that assurance. For flow monitors, however, the daily calibration error tests, which check the internal electronics of the flow monitor but do not evaluate the actual flow measurement capability of the instrument, do not provide the necessary assurance. Therefore, in today's rulemaking, EPA is proposing a new flow monitor quality assurance requirement, the ''flow-to-load test,'' to provide a reasonable indicator of continued flow monitor accuracy between successive RATAs. The flow-to-load test has been discussed in detail under section III.M. of this preamble.

If a RATA is failed or aborted due to a problem with the CEMS, proposed section 2.3.2 of Appendix B would specify that the monitoring system is out-of-control as of the hour in which the test is failed or aborted. Data from the monitoring system would remain invalid until the hour of completion of a subsequent successful hands-off RATA. This proposed requirement is essentially the same as the out-of-control provision in the current rule, except that it would extend the definition of out-of-control to include RATAs that are aborted prior to completion due to a problem with the CEMS. Note, however, that a RATA which is terminated for a reason unrelated to monitor malfunction (e.g., process operating problems or unit outage) would not trigger an out-of-control period.

For multiple-load flow RATAs, each load level would be treated as a separate RATA. Therefore, if a flow RATA is failed at a particular load level, previously-passed RATAs at the other loads would not have to be repeated unless the flow monitor has to be re-linearized. In that case, a subsequent 3-load RATA would be required.

If a daily calibration error test is failed during a RATA test period, proposed section 2.3.2 of Appendix B would require invalidation of the RATA, and an out-of-control period would begin with the hour of the failed calibration error test. The RATA could not to be re-started until a subsequent calibration error test had been passed, following corrective actions.

Proposed section 2.3.2 of Appendix B further specifies that when the RATA of a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions) is failed and that same CO_2 (or O_2) monitor also serves as the diluent component in a NO_X-diluent (or SO_2-diluent) monitoring system, then both the CO_2 (or O_2) monitor and the associated NO_X-diluent (or SO_2-diluent) system would be considered to be out-of-control until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems are in-control and have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of Appendix A. The beginning of the out-of-control period for each monitoring system would be the hour of completion of the failed or aborted RATA of the CO_2 (or O_2) monitor. The lengths of the out-of-control periods would, therefore, be determined from the same reference point for both the CO_2 (or O_2) monitoring system and the NO_X-diluent (or SO_2-diluent) monitoring system.

Today's proposal would clarify the way in which RATA results are to be reported to EPA in the electronic quarterly report required under § 75.64. Proposed section 2.3.2 of Appendix B specifies that only the results of completed and partial RATAs that affect data validation would have to be reported. That is, all completed passed RATAs, all completed failed RATAs, and all RATAs aborted due to a problem with the CEMS would have to be included in the quarterly report. Therefore, aborted RATA attempts followed by corrective maintenance, re-linearization of the monitor, or any other adjustments other than those allowed under proposed section 2.1.3 of Appendix B would have to be reported. RATAs which are aborted or invalidated due to problems with the reference method or due to operational problems with the affected unit(s) would not need to be reported, because such runs do not affect the validation status of emission data recorded by the CEMS. In addition, aborted RATA attempts which are part of the process of optimizing a monitoring system's performance would not have to be reported, provided that in the period from the end of the aborted test to the commencement of the next RATA attempt: (1) no corrective maintenance or re-linearization of the CEMS is performed, and (2) no adjustments other than the calibration adjustments allowed under proposed section 2.1.3 of Appendix B are made. However, such RATA runs would still have to be documented and kept on-site as part of the official test log.

Whenever a required RATA has not been completed by its deadline, section 2.3.3 of Appendix B of today's proposed rulemaking would provide a grace period of 720 unit operating hours in which to complete the test. Data validation during a grace period would be done according to the applicable provisions of proposed section 2.3.2 of Appendix B. Proposed section 2.3.3 would specify that if the RATA is not completed by the end of the grace period, data from the CEMS would become invalid upon expiration of the grace period and remain invalid until the hour of completion of a subsequent successful hands-off RATA.

EPA has proposed a 720 unit operating hour RATA grace period because the Agency believes this will allow the facility sufficient time to schedule the RATA, to provide all required test notifications, and to complete the testing. The proposed grace period would be based on unit

operating hours rather than clock hours, because this is believed to be more equitable for peaking and cycling units. Data validation during the grace period would be prospective, i.e., data from the monitoring system would be considered valid during the grace period until the time of the RATA. If the RATA is failed or aborted due to a problem with the CEMS, data would be invalidated from the hour in which the test is failed or aborted, forward. Data would not be invalidated retrospectively back to the beginning of the grace period. Several utilities have expressed a preference for a grace period with prospective data invalidation, because it is simple to implement and is consistent with other part 75 provisions for which data invalidation is prospective when a test is failed (see Docket A–97–35, Item II–E–23).

4. Recertification of Gas and Flow Monitors

Today's proposed rule would revise § 75.20(b)(3) concerning data validation during recertification test periods. In the January 11, 1993 rule, as amended on May 17, 1995, § 75.20(b)(3) specifies that for any replacement, change, or modification to a monitoring system requiring recertification of the CEMS, all data from the CEMS are considered invalid from the hour of that replacement, change, or modification until the hour of completion of all required recertification tests. Today's rulemaking proposes to conditionally allow emission data generated by the CEMS during a recertification test period to be used for part 75 reporting, provided that the required tests are successfully completed in a timely manner and that certain data validation rules are followed during the recertification test period. Proposed sections 6.2, 6.3.1, and 6.5 of Appendix A would allow these new data validation procedures to also be applied to the initial certification of monitoring systems. The proposed revisions are based, in part, on policy guidance issued by EPA to address the initial certification of CEMS when a wet scrubber is installed on an affected unit (see Docket A–97–35, Item II–I–9, Policy Manual, Question 16.10). The intent of that policy guidance and of today's proposal is to minimize the number of hours of substitute data or maximum potential values that must be reported during a monitor certification or recertification period.

In proposed § 75.20(b)(3), specific rules are provided for data validation during the recertification test period. The recertification test period would begin with the first successful calibration error test after making the change to the CEMS and completing all necessary post-change adjustments, re-programming, linearization, etc. of the CEMS. The post-change activities could also include preliminary tests such as trial RATA runs or a challenge of the monitor with calibration gases. The first successful calibration error test following all of these activities would be known as a probationary calibration error test. Data from the CEMS would be considered invalid from the hour in which the replacement, modification, or change to the system is commenced until the hour of completion of the probationary calibration error test, at which point, the data status would become conditionally valid.

Today's proposal would place a specific time limit on the length of the recertification test period, depending upon the type(s) of test(s) required. If a linearity test or cycle time test is required, the test would have to be completed within 168 unit operating hours of the hour in which the probationary calibration error test was passed, marking the beginning of the recertification test period. If a RATA is required, it would have to be completed within 720 unit operating hours. If a 7-day calibration error test were required, it would have to be completed within 21 unit operating days. Routine daily calibration error tests would continue to be done as required by part 75 throughout the recertification test period. If a particular recertification test is not completed within the specified number of hours, data validation would be done as follows. For a late linearity test, RATA, or cycle time test that is passed on the first attempt, or for a late 7-day calibration error test (whether or not it is passed on the first attempt), data from the monitoring system would be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. However, for a late linearity test, RATA, or cycle time test that is failed on the first attempt or aborted on the first attempt due to a problem with the monitor, all conditionally valid data from the monitoring system would be invalidated from the hour of the probationary calibration error test that initiated the original recertification test period to the hour of completion of the late recertification test. Data would remain invalid until successful completion of the failed/aborted test and any additional recertification or diagnostic tests that are required as a result of changes made to the monitoring system to correct the problem(s) that caused failure of the late recertification test.

A conditionally valid status would be assigned to emission data generated by a CEMS during a recertification test period. The conditionally valid data status would begin with the first hour of the recertification test period (i.e., the hour in which the probationary calibration error test is passed, following completion of all necessary monitor adjustments, preliminary tests, etc.). The conditionally valid status of the CEMS data would continue throughout the recertification test period, provided that the required recertification tests are done ''hands-off'' (i.e., with no adjustments, reprogramming, etc. of the CEMS other than the calibration adjustments allowed under proposed section 2.1.3 of Appendix B) and provided that the recertification tests and required daily calibration error tests continue to be passed. If all of the required recertification tests and calibration error tests are passed hands-off, with no failures and within the required time period, then all of the conditionally valid emission data recorded by the CEMS during the recertification test period would be considered quality assured and suitable for part 75 reporting. Note, however, that if a required recertification test has not been completed by the end of a calendar quarter, the owner or operator would indicate this by using a suitable conditional data flag in the electronic quarterly report for that quarter. The owner or operator would be required to resubmit the report for that quarter if the required recertification test is subsequently failed. In the resubmitted report, the owner or operator would use the appropriate missing data routine in § 75.31 or § 75.33 to replace each hour of conditionally valid data that was invalidated by the failed recertification test with substitute data. In addition, if conditionally valid data is submitted to the Agency in any quarterly report, the owner or operator would have to indicate in the end of the year compliance report required under § 72.90 whether the final status of the conditionally valid data has been determined. Note that in certain instances where a recertification test period spans two calendar quarters, it may be possible to avoid use of the conditional data flag and quarterly report resubmittal. If a required recertification test(s) is completed no later than 30 days after the end of a calendar quarter (i.e., prior to the quarterly report submittal deadline), the test data and results may be submitted

with the quarterly report, even though the test dates are from the next calendar quarter. If the recertification test(s) is passed, this would allow the ''conditionally valid'' data to be reported as quality assured, in lieu of using a conditional data flag. If the test(s) is failed, conditionally valid data could be replaced with substitute data, as appropriate, and resubmittal of the quarterly report would not be necessary.

If a recertification test is failed or aborted due to a problem with the CEMS or if a routine daily calibration error test is failed during a recertification test period, proposed § 75.20(b)(3) specifies that data validation would be done as follows:

(1) If any required recertification test is failed, the test would have to be repeated. If any recertification test, other than a 7-day calibration error test, is failed or aborted due to a problem with the CEMS, the original recertification test period would end and any necessary maintenance activities, adjustments, linearizations, and reprogramming of the CEMS would need to be completed before a new recertification test period could begin. The new recertification test period would begin with a probationary calibration error test. The tests that would be required in this new recertification test period would include any tests that were required for the initial recertification event which were not successfully completed and any recertification or diagnostic tests required as a result of changes that were made to the monitoring system to correct the problems that caused failure of the recertification test;

(2) If a linearity test, RATA, or cycle time test is failed or aborted due to a problem with the CEMS, all conditionally valid emission data recorded by the CEMS would be invalidated from the hour of commencement of the original recertification test period to the hour in which the test is failed or aborted. Data from the CEMS would remain invalid until the hour in which a new probationary calibration error test is passed following all of the necessary maintenance procedures, diagnostic tests, etc., at which time the conditionally valid status of emission data from the CEMS would begin;

(3) If a 7-day calibration error test is failed within the recertification test period, the test would have to be re-started. Previously-recorded conditionally valid emission data from the CEMS would not be invalidated by a failed 7-day calibration error test unless the calibration error on the day of the failed 7-day calibration error test exceeded twice the performance specification in section 3 of Appendix A (causing the monitor to be considered out-of-control); and

(4) If a calibration error test is failed during a recertification test period, the CEMS would be considered out-of-control as of the hour in which the calibration error test is failed. Emission data from the CEMS would be invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test following corrective action, at which time the conditionally valid data status would resume. Failure to perform a required daily calibration error test during a recertification test period would also cause data from the CEMS to be invalidated prospectively from the hour in which the calibration error test was due until the hour of completion of a subsequent successful calibration error test. Following a failed or missed calibration error test, no recertification tests could be performed until the required subsequent calibration error test had been passed.

5. Recertification and QA

In today's proposed rule, a new section, 2.4, entitled ''Recertification, Quality Assurance, and RATA Deadlines'' would be added to Appendix B. The purpose of this section would be to clarify the inter-relationship between normal quality assurance testing of CEMS and recertification events and to further clarify how RATA deadlines are determined. Appendix B to part 75 currently requires periodic (daily, quarterly, and semiannual or annual) quality assurance tests of all CEMS. The required daily QA tests include calibration error tests of all monitors and interference checks of flow monitors. Quarterly QA tests include linearity checks of gas monitors and leak checks of differential pressure-type flow monitors. The required semiannual or annual QA tests for all types of CEMS are RATAs.

Under the current rule, when a significant change is made to a CEMS which affects the ability of the monitoring system to accurately read and record emissions data, § 75.20(b) specifies that the CEMS must be recertified. To recertify a monitoring system, one or more of the following tests that were performed for initial certification of the CEMS must be repeated. That is, depending upon the nature of the change made to a CEMS, one or more of the following tests may be required for recertification: (1) calibration error test, (2) cycle time test, (3) linearity check, (4) RATA, or (5) DAHS verification. Notice that recertification tests (1), (3), and (4) are the same types of tests that are done for routine daily, quarterly, and semiannual or annual QA. There is, therefore, a connection between routine QA tests and recertification tests. Proposed § 75.20(b) would further clarify that any change to a CEMS that does not require a RATA would not be considered a recertification event, and, therefore, would not require a recertification application. In such cases, the required tests would be considered diagnostic tests.

Routine QA tests are generally planned and scheduled in advance, while recertification tests are performed on an as-required basis. Despite this, it is sometimes possible to coordinate component replacements or other changes to a CEMS with the QA test schedule for the CEMS. For instance, suppose that in a particular quarter, a CEMS component is replaced, and a RATA is required to recertify the monitoring system. Suppose, further, that in the quarter of the component replacement, the annual RATA is due, but has not yet been conducted. In this case, the recertification RATA could serve a dual purpose, i.e., to recertify the CEMS and to meet the annual RATA requirement. For this reason, EPA proposes to recommend in today's rule that, to the extent practicable, component replacements, system upgrades, and other events that require recertification be coordinated with the periodic (daily, quarterly, and semiannual or annual) QA testing required under Appendix B. Proposed section 2.4 of Appendix B clarifies that when a particular test is done for the dual purpose of recertification and routine QA, the data validation rules in § 75.20(b)(3) pertaining to recertification would take precedence and would be followed. In a similar manner, a required diagnostic test (e.g., linearity check) could also be used to satisfy a quarterly linearity test requirement.

Proposed section 2.4 of Appendix B emphasizes that, in general, whenever a RATA is performed, whether for QA purposes, recertification purposes, or both, the projected deadline for the next RATA (i.e., whether the next test is due in 2 or 4 QA operating quarters) would be established based upon the percentage relative accuracy obtained. For 2-load and 3-load flow RATAs, the projected deadline for the next RATA would be established according to the highest relative accuracy at any of the loads tested. There would, however, be two important exceptions to this for single-load flow RATAs. Irrespective of

the relative accuracy percentage obtained, the results of a single-load flow RATA could only be used to establish an annual RATA frequency if: (1) the single-load flow RATA is specifically required under section 2.3.1.3(b) of Appendix B for flow monitors installed on peaking units and bypass stacks, or (2) the single-load RATA is allowed under proposed section 2.3.1.3(c) of Appendix B for ≥ 85.0 percent historical unit operation at a single-load level. No other single-load flow RATA could be used to establish an annual frequency; however, a 2-load flow RATA could be performed in place of any required single-load RATA, in order to achieve an annual frequency.

6. Data From Non-Redundant Backup Monitors

Today's rule proposes to revise the quality assurance and data validation requirements in § 75.20(d) for non-redundant backup monitoring systems. Under the May 17, 1995 rule, a ''non-redundant backup monitoring system'' is defined as a ''cold'' backup monitoring system which is brought into service on an as-needed basis, rather than being operated continuously. Non-redundant backup monitors must be initially certified at each location at which they are to be used, but unlike ''redundant backup'' monitors which are operated continuously and kept on ''hot-standby,'' non-redundant backup systems are not required to meet the daily and quarterly quality assurance requirements of Appendix B, except when they are actually used for data reporting. A linearity test of each non-redundant backup gas monitor is required before it is placed in service, and each non-redundant backup flow monitor must pass a calibration error test before being used to report data. The use of non-redundant backup monitors is restricted to 720 hours a year at a particular unit or stack, unless a 7-day calibration error test is passed. A periodic recertification RATA of each non-redundant backup monitor is required at least once every two years, at each location where it is to be used.

Section 75.20(d) of today's proposal would clarify and expand the definition of a non-redundant backup monitoring system. Under the proposal, two distinct types of non-redundant backup systems would be defined: (1) type-1 is a system that has its own separate probe, sample interface, and analyzer (e.g., a portable gas monitoring system), and (2) type-2 is a system consisting of one or more like-kind replacement analyzers that use the same sample probe and interface as the primary monitoring system. This would include non-redundant backup analyzers that are used to meet the dual span and range requirements for SO_2 or NO_X under proposed sections 2.1.1.4 and 2.1.2.4 of Appendix A.

The ''type-1'' system is the familiar non-redundant backup system described in the current version of part 75. However, the ''type-2'' system is a new kind of non-redundant backup monitoring system. EPA believes that allowing limited use of type-2 monitoring systems will encourage facilities that do not have redundant backup monitors to perform better maintenance on their primary analyzers. The Agency is concerned that primary analyzers with excessive, recurring daily calibration drift (i.e., monitors that fail calibration error tests more often than expected) are sometimes kept in service to avoid using substitute data, when the analyzers should be in the shop for maintenance. If the monitor readings tend to drift low from day to day, this can result in under-reporting of emissions, because data validation for daily calibrations under part 75 is prospective. That is, data are invalidated from the hour of a failed calibration error test forward, while data recorded from the hour of the previous successful calibration to the hour of the failed calibration are considered valid. EPA believes that allowing limited use of type-2 non-redundant backup monitoring systems would provide a simple way (i.e., like-kind analyzer replacement) for primary analyzers to be properly maintained and repaired with minimal data loss.

Today's proposal would retain the requirement for type-1 non-redundant backup monitoring systems to be initially certified (except for a 7-day calibration error test) at each location at which they are to be used. However, type-2 systems would require no initial certification. Both types of systems would have to pass a linearity test (for gas monitors) or a calibration error test (for flow monitors) each time that they were used to report emission data. For a type-2 ''mix-and-match'' NO_X monitoring system consisting of one primary analyzer and one like-kind replacement analyzer, only the like-kind replacement analyzer would have to pass a linearity test, provided that the primary analyzer is operating and not out-of-control with respect to any of its quality assurance requirements. When a non-redundant backup monitoring system is brought into service, emission data from the non-redundant backup system could be deemed conditionally valid during the linearity test period, as follows. After making the like-kind replacement and prior to conducting the linearity test, a probationary calibration error test could be done to begin the period of conditionally valid data. If the linearity test is then passed within 168 unit operating hours of the probationary calibration error test, the conditionally valid data would be validated. However, if the linearity test is either failed, aborted due to a problem with the CEMS, or not completed as required, then all of the conditionally valid data would be invalidated beginning with the hour of the probationary calibration error test, and data from the non-redundant backup CEMS would remain invalid until the hour of completion of a successful linearity test.

Under today's proposal, when a non-redundant backup system is used for part 75 reporting, the bias adjustment factor (BAF) from the most recent RATA of the system would be applied to the data generated by the system. If no RATA results were available for a type-2 system, the primary monitoring system BAF would be applied to the data generated by the type-2 system.

Today's proposal would retain the restrictions of the current rule, which limit the annual usage of a non-redundant backup monitoring system to 720 hours at a particular location (unit or stack). To use a non-redundant backup system for more than 720 hours per year at a particular location would require a RATA of the system at that location. For type-1 systems, a recertification RATA would be required at least once every eight calendar quarters at each location at which the system is to be used. All non-redundant backup monitoring systems (type-1 and type-2) would have to be assigned unique system and component identification numbers and would have to be included in the monitoring plan for the unit or stack.

7. Missed QA Test Deadlines

As discussed above under the subsections on ''Linearity Tests'' and ''Relative Accuracy Test Audits,'' proposed sections 2.2.4 and 2.3.3 of Appendix B to today's rulemaking would allow a grace period in which to perform required linearity tests and RATAs whenever a test cannot be completed by the end of the quarter in which it is due. EPA believes it is appropriate to allow a grace period because circumstances beyond the control of the owner or operator (e.g., unplanned unit outages) sometimes arise which prevent the deadline for a quality assurance test from being met.

The proposed linearity grace period is 168 unit operating hours, and the proposed RATA grace period is 720 unit operating hours. A linearity grace period

could only be used to satisfy the linearity requirement from a previous quarter. For any RATA (or RATAs, if more than one attempt is made) conducted during a grace period, the deadline for the next RATA would be calculated from the quarter in which the RATA was originally due, not from the quarter in which the RATA is actually completed.

Data validation during a grace period would be done according to the applicable provisions in proposed section 2.2.3 of Appendix B (for linearities) or section 2.3.2 of Appendix B (for RATAs). Data from a CEMS would become invalid upon expiration of a grace period if the required linearity test or RATA had not been completed. Data from the CEMS would remain invalid after the expiration of the grace period until the required test is successfully completed.

P. Appendix D

1. Pipeline Natural Gas Definitions

Background

Appendix D provides an optional protocol by which oil-fired and gas-fired units may account for their SO_2 mass emissions. Under the definitions of ''oil-fired'' and ''gas-fired'' in § 72.2, Appendix D may be used to measure SO_2 emissions from gaseous fuels only if the gaseous fuel's sulfur content is less than or equal to that of natural gas.

In developing Appendix D, EPA assumed that virtually all of the gaseous fuel combusted by affected units in the Acid Rain Program would be pipeline natural gas. Section 2.3 of Appendix D of the January 11, 1993 rule allowed for accounting for SO_2 emissions from gaseous fuel using EPA's ''National Allowance Database (NADB) emission rate.'' The NADB was used to establish a baseline of historical SO_2 emissions in order to allocate allowances. For the vast majority of units combusting pipeline natural gas, NADB used the historical heat input from gas and an emission rate of 0.0006 pounds of SO_2 per measured million British thermal units (lb/mmBtu) (see Docket A–92–06; Docket A–94–16, Item II–F–2). This default factor is derived from EPA Publication AP–42 and is based on a sulfur content of 0.2 grains per 100 standard cubic feet of gaseous fuel (gr/100 scf) (see Docket A–97–35, Item II–I–1). Use of this default SO_2 emission rate factor for pipeline natural gas was clarified by EPA in its Acid Rain Policy Manual (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.4).

Section 2.3.2 of Appendix D, as revised by the May 17, 1995 direct final rule, explicitly allows owners or operators to use a default emission factor of 0.0006 (lb/mmBtu) to estimate SO_2 emissions during hours in which pipeline natural gas is combusted. Alternatively, section 2.3.1 of Appendix D, also as revised by the May 17, 1995 direct final rule, allows for determining SO_2 emissions from any gaseous fuel with a sulfur content no greater than natural gas by performing daily fuel sampling, analyzing the sulfur content of the gaseous fuel, and multiplying that sulfur content in grains per 100 standard cubic feet (gr/100scf) times the volume of gaseous fuel combusted. Units combusting gaseous fuels with a total sulfur content greater than natural gas (i.e., > 20 gr/100scf) are not allowed to use the procedures of Appendix D and must instead use an SO_2 CEMS and a flow monitor to determine SO_2 mass emissions. This limitation is explicitly stated in § 75.11(e)(4), as revised on November 20, 1996.

The definition of ''natural gas'' in § 72.2, as revised by the May 17, 1995 direct final rule, indicates that the sulfur content of natural gas is ''1 grain or less hydrogen sulfide per 100 standard cubic feet, and 20 grains or less total sulfur per 100 standard cubic feet.'' This definition was taken from Requirements of the Federal Energy Regulatory Commission (FERC) for regulation of the transmission of natural gas. ''Pipeline natural gas'' is also defined in § 72.2. However, the definition is simply ''natural gas that is provided by a supplier through a pipeline,'' and provides no specifications for sulfur content or hydrogen sulfide content.

Section 2.3.2.2 of Appendix D requires documentation of the contractual sulfur content of pipeline natural gas from the supplier. This documentation was intended to demonstrate that the natural gas is supplied through a pipeline, as well as that it meets the sulfur content definition for natural gas.

Questions over the applicability of Appendix D and the apparent inconsistencies between the definitions ''natural gas'' and ''pipeline natural gas'' in § 72.2 and the provisions of section 2.3 of Appendix D have caused confusion during program implementation since the May 17, 1995 direct final rule. Some utilities have interpreted section 2.3.2.2 of Appendix D to allow pipeline natural gas to have a sulfur content as high as 20 gr/100 scf, which is one hundred times higher than the sulfur content upon which the 0.0006 lb/mmBtu emission factor is based. During the process of applying for certification of monitoring equipment for six gas-fired units, one utility indicated to the Agency that it intended to use a default emission rate of 0.0006 lb/mmBtu and heat input to account for SO_2 mass emissions from propane liquefied petroleum gas (see Docket A–97–35, Item II–D–6). Based upon the information provided by the utility in its monitoring plan for the units, the sulfur content of propane was several times higher than that of pipeline natural gas, with a range of sulfur content between 0.08 and 2.72 gr/100 scf, compared to a typical sulfur content of 0.2 gr/100 scf for pipeline natural gas, upon which the default SO_2 emission rate of 0.0006 lb/mmBtu is based. Later information submitted by the utility indicated that during the previous three years, the sulfur content of propane combusted at that plant had an average value of 0.83 gr/100 scf and a maximum value of 2.20 gr/100 scf (see Docket A–97–35, Item II–D–60). EPA rejected the utility's monitoring approach using the default emission rate for pipeline natural gas because it would have resulted in an underestimation of SO_2 emissions, as well as not following the procedures of Appendix D (see Docket A–97–35, Item II–C–2).

Other utilities have tried to use the default SO_2 emission rate of 0.0006 lb/mmBtu for higher sulfur gaseous fuels, such as digester gas (see Docket A–94–16, Item II–D–71). EPA issued policy guidance to ensure that other utilities were aware that the default SO_2 emission rate of 0.0006 lb/mmBtu should only be used for pipeline natural gas with a low sulfur content of 0.2 gr/100 scf (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.15, as originally published in March 1996). However, several utilities were concerned that this excluded some pipeline natural gas (see Docket A–97–35, Items II–B–3, II–E–16). As stated in the technical support document for the May 17, 1995 direct final rule, EPA had intended that all pipeline natural gas would qualify for use of the default SO_2 emission rate of 0.0006 lb/mmBtu. Therefore, the Agency revised its guidance to clarify that a facility needed only to document that it was using pipeline natural gas, without documenting a sulfur content of 0.2 gr/100 scf (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.15, as revised in June 1996). During this process, the Agency became concerned that the definition of pipeline natural gas in § 72.2 was not clear enough and that the sulfur content documentation required for pipeline natural gas in section 2.3.2.2 of Appendix D was confusing and possibly inappropriate.

Discussion of Proposed Changes

For the definition of pipeline natural gas in § 72.2, today's proposal includes a revised definition that would indicate pipeline natural gas is low in the sulfur-bearing compound hydrogen sulfide (H_2S). The proposed revised definition would specifically include the maximum hydrogen sulfide content for pipeline natural gas permitted by fuel purchase or transportation contracts. The hydrogen sulfide content of pipeline natural gas is proposed to be up to 0.3 gr/100 scf.

In addition, section 2.3 of Appendix D would be revised. As under the current rule provisions, sources would be allowed to use a default SO_2 emission rate of 0.0006 lb SO_2/mmBtu in conjunction with unit heat input to calculate the SO_2 mass emission rate during the combustion of pipeline natural gas. In order to demonstrate that the pipeline natural gas qualifies to use the default SO_2 emission rate of 0.0006 lb/mmBtu, it would be necessary for the designated representative to provide information in the monitoring plan on the gas's maximum hydrogen sulfide content from the facility's purchase contract with the pipeline gas supplier or from the pipeline natural gas supplier's transportation contract. In such contracts, or in the tariff sheets associated with them, the pipeline gas supplier typically agrees to provide natural gas with a maximum hydrogen sulfide content of 0.25 gr/100 scf or 0.30 gr/100 scf. If a facility has previously submitted contract information from its pipeline gas supplier containing a limit on the sulfur content, this information typically also verifies the limit on the hydrogen sulfide content. For pipeline natural gas, it would not be necessary to provide sampling information to verify that the hydrogen sulfide content actually meets the quality specification limit on the hydrogen sulfide content stated in the definition of pipeline natural gas.

If a facility wanted to demonstrate that another gaseous fuel had an SO_2 emission rate no greater than pipeline natural gas, and thus, could use the default emission rate factor of 0.0006 lb/mmBtu, the designated representative would provide sulfur content and GCV information in the monitoring plan for the unit or could petition under § 75.66(i) after initial certification for the unit. It would be necessary for the designated representative to demonstrate that the gaseous fuel has an SO_2 emission rate no greater than 0.0006 lb/mmBtu. The designated representative would need to provide at least 720 hours of data for the demonstration. The data could come from the fuel supplier, if the fuel came from a gas supplier.

For all units using Appendix D, proposed section 2.3.3 would require the designated representative to provide information to the Agency demonstrating that the total sulfur content of the gaseous fuel meets the requirements of Appendix D and that the unit meets the § 72.2 definition of ''gas-fired'' or ''oil-fired.'' Additionally, the gas-fired definition would be revised to indicate that the restriction of burning gaseous fuels containing no more sulfur than natural gas is actually a restriction on the total sulfur in the fuel. The gaseous fuel's total sulfur content would have to be shown to be less than or equal to 20 grains total sulfur per 100 standard cubic feet of gaseous fuel.

Rationale

The Agency proposes to introduce specific hydrogen sulfide content values into the definition of pipeline natural gas in order to provide a guideline that will separate gaseous fuels with a higher sulfur content from low sulfur pipeline natural gas. The maximum hydrogen sulfide content of 0.3 gr/100 scf is being proposed for two reasons. First, hydrogen sulfide contents of 0.25 or 0.3 gr/100 scf are typically required under pipeline gas transmission contracts, and should be relatively easy to document (see Docket A–97–35, Item II–E–19). In addition, 0.2 gr/100 scf is the sulfur content equivalent to the default emission rate factor of 0.0006 lb/mmBtu from the Agency's AP–42 emission factors that may be used by units combusting pipeline natural gas under section 2.3.2 of Appendix D (see Docket A–97–35, Item II–A–6). A maximum hydrogen sulfide content of 0.3 gr/100 scf corresponds to this default emission rate far more closely than a total sulfur content of 20.0 gr/100 scf or a hydrogen sulfide content of 1.0 gr/100 scf and, yet, would allow for some variability in the hydrogen sulfide content above a 0.2 gr/100 scf average. EPA believes that all or virtually all pipeline natural gas that is supplied through a pipeline for commercial use can meet these qualifications.

Pipeline natural gas is composed predominantly of methane (CH_4). Hydrogen sulfide is the predominant molecule containing sulfur in pipeline natural gas. Therefore, restricting the hydrogen sulfide content of pipeline natural gas to 0.3 gr/100 scf serves as a proxy for a limit on the total sulfur content, while being relatively easy to document. This revised definition of pipeline natural gas would also serve to restrict the default emission rate factor from being inappropriately applied to higher sulfur gaseous fuels, such as liquefied petroleum gas (see Docket A–97–35, Item II–D–6) or digester gas (see Docket A–94–16, Item II–D–71).

Appendix D of today's proposed rule would be revised to clarify the documentation requirements for sulfur content and hydrogen sulfide content of gaseous fuel, including pipeline natural gas. The original wording of section 2.3.2.2 implied that pipeline natural gas only need to have a total sulfur content of 20 gr/100 scf, roughly 100 times the sulfur content associated with the default emission rate of 0.0006 lb/mmBtu. Some utilities found this confusing (see Docket A–97–35, Items II–D–6, II–E–10). Therefore, EPA issued guidance to clarify that the default emission rate factor was only intended to apply to lower sulfur pipeline natural gas (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.15).

However, some utilities using pipeline natural gas were concerned that because their fuel suppliers were not willing to certify or agree to a sulfur content of 0.3 gr/100 scf by contract, they might be required to perform daily gas sampling (see Docket A–97–35, Items II–B–3, II–E–15, II–E–16). This was not the Agency's intent. The Agency merely wishes to ensure that facilities provide adequate documentation to demonstrate that the unit will not be underestimating SO_2 emissions for a high sulfur gaseous fuel by using an inappropriate default emission rate factor that applies to extremely low sulfur gas. Similar to EPA's Policy Manual Question 2.15 referred to above, a facility would need only to provide the fuel quality specification for total sulfur content and hydrogen sulfide from the pipeline supplier, or from the tariff sheet for the pipeline, in order to qualify to use the default emission rate.

If a facility intends to use the default emission rate factor for a gaseous fuel other than pipeline natural gas, sulfur content and GCV data would have to be provided and analyzed to demonstrate that the fuel has an SO_2 emission rate no greater than 0.0006 lb/mmBtu. A minimum of 720 hours of data would be required for the demonstration. Each hourly value of the total sulfur content (in gr/100 scf) would be divided by the GCV value (in Btu/100 scf) and then multiplied by a conversion factor of 10^6 Btu/mmBtu. This would provide a ratio of the number of grains of sulfur in the fuel to the heat content of the fuel. For pipeline natural gas with an assumed SO_2 emission rate of 0.0006 lb/mmBtu, a sulfur content of 0.2 gr/100 scf and a

GCV value of 100,000 Btu per hundred scf, the value of the ''sulfur-to-heat content'' ratio is 2.0 gr/mmBtu. Therefore, a candidate gaseous fuel would qualify to use the default SO_2 emission rate of 0.0006 lb/mmBtu for part 75 reporting purposes if the 720 hours of historical data demonstrate that the mean value of the sulfur-to-heat content ratio is 2.0 gr/mmBtu or less.

To demonstrate that a unit qualifies to use Appendix D when combusting a gaseous fuel, the designated representative for the facility would be required to show that the gaseous fuel has a total sulfur content of 20 grains/100 scf or less. This demonstration would apply to all gaseous fuels. For gaseous fuels other than pipeline natural gas, the sulfur content information could come either from contractual information on the sulfur content based on routine vendor sampling and analysis or from historic fuel sampling data to show the gaseous fuel's sulfur content (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.15). For gaseous fuels that are produced in batches or lots with a relatively uniform sulfur content, such as liquefied petroleum gases, it would be sufficient to provide historical information on each batch over the past year. This approach was accepted by the Agency for six units combusting liquefied petroleum gas (see Docket A–97–35, Items II–C–14 and II–D–22).

In addition to documenting the total sulfur content of the fuel, the owner or operator would be required to submit certain other fuel-specific information. As previously noted, for units combusting pipeline natural gas, a designated representative would be required to provide contractual information to demonstrate that the natural gas is supplied under specification and has a hydrogen sulfide content less than or equal to 0.3 gr/100 scf. And historical data would have to be provided, as described above, to obtain permission to use the default SO_2 emission rate of 0.0006 lb/mmBtu for a fuel other than pipeline natural gas. For other gaseous fuels that are not produced in batches with relatively uniform sulfur content, such as gaseous fuel generated through an industrial process (e.g., digester gas from a paper mill), since the sulfur content of the gaseous fuel could be highly variable, section 2.3.3.4 of today's proposed revisions to Appendix D would require a minimum of 720 hours of historical data documenting the sulfur content of the fuel under representative operating conditions. This information would allow the Agency to determine how variable the sulfur content is and if the daily sampling procedure under section 2.3.1 of Appendix D is sufficient to capture this variability without allowing the underestimation of sulfur content. If the sulfur variability were too great, continuous sampling using a gas chromatograph and hourly reporting of sulfur content would be required under today's proposed rule.

2. Fuel Sampling

(a) *Fuel Oil.*

Background

Diesel fuel is distillate fuel oil of grades No. 1 or 2. Diesel fuel is heavily refined and has a much lower sulfur content and greater consistency than other grades of fuel oil. Section 2.2 of Appendix D to the May 17, 1995 direct final rule provides three options for sampling of diesel fuel and two options for sampling of other fuel oils. First, for all fuel oils, including diesel fuel, daily manual sampling is allowed. Second, diesel fuel and other fuel oils may also be sampled continuously using an automated sampler according to ASTM D4177–82 (Reapproved 1990), either using continuous drip sampling or flow proportional sampling. The samples would then be mixed to form a daily composite sample. Third, diesel fuel may be sampled ''as-delivered,'' upon receipt of a shipment. These sampling approaches were selected to ensure that sulfur content values would be as accurate as possible, would not underestimate SO_2 mass emissions, and would account for any variability in the sulfur content of fuel.

Many utilities have expressed concern about the cost of daily oil sampling (see Docket A–97–35, Items II–D–18, II–D–20, II–E–13, II–E–14). Some utilities indicated that for a unit that burns oil every day, the cost of daily oil sampling is greater than the cost of SO_2 CEMS and flow monitors. Furthermore, industry representatives provided information indicating that within a given shipment of fuel oil from a supplier, the variability in sulfur content is low (see Docket A–97–35, Items II–D–18 and II–D–59). Many companies already have state or Federal requirements for sampling of fuel from each truck delivery or in a storage tank on site at the plant whenever fuel is added to the storage tank (see Docket A–97–35, Item II–D–93). The storage tank is a tank at a plant that holds oil that is actually combusted by the unit on that day. In other words, no fuel will be blended between the time when a fuel lot is transferred to the storage tank and when the fuel is combusted in the unit. In other cases, such as EPA's NSPS regulations for industrial boilers under 40 CFR part 60, subpart Db, companies keep copies of fuel receipts from the supplier to indicate the sulfur content is below the required sulfur content. Based upon this information, EPA is proposing to reduce the required sampling frequency for fuel oil. This would be a significant reduction in burden and cost of using Appendix D, without causing underestimation of SO_2 emissions.

Discussion of Proposed Changes

Several utilities suggested that the Agency propose to allow sampling of each delivery of oil (see Docket A–97–35, Items II–D–18, II–D–20, II–E–13, II–E–22). Under this approach, either a facility or its supplier would sample each truck or barge containing oil before the fuel is transferred into a tank at the plant. If a delivery shipped in a group of trucks were purchased under the same order and were specified to have the same gross calorific value, density, and sulfur content, then only one sample would be necessary for the group of trucks. Samples taken by the supplier would not need to be split and kept on hand at the site. This approach is currently allowed only for diesel fuel under section 2.2.1.2 of Appendix D, but would be extended to apply to all fuel oils under today's proposed rule. This approach would be particularly useful to a facility that receives large, infrequent deliveries of fuel or to a facility that already has other State or Federal regulations requiring sampling of each truck or barge delivered to the plant.

A similar approach suggested by another industry representative, allowing facilities to use a sample of oil taken from a tank belonging to the supplier before the oil is delivered, is also proposed in today's rulemaking. The supplier could take the sample and the facility would be able to use that value as long as it keeps records of the fuel analysis results from the supplier. This approach would be particularly useful to a facility that receives a delivery of oil from a single supplier's tank that is shipped in many different trucks. This approach also would be useful for a small facility that would prefer to rely on samples taken by the supplier rather than taking its own samples and paying for their analysis.

Finally, the Agency proposes a third sampling approach, allowing a facility to sample oil manually from its storage tank at the plant whenever oil is added to the tank. This approach would yield samples that are more representative of the oil combusted because it would include any fuel remaining in the tank as well as all fuel added. Sampling from the storage tank at the plant would be

useful to a facility that burns oil infrequently and adds oil to its storage tank infrequently. It also would be helpful where a facility already has other State or Federal regulations requiring sampling after adding fuel to the storage tank.

Both the ''before delivery'' and ''as delivered'' sampling approaches would require a sample for each ''lot'' of oil; consequently, a suitable definition of a ''lot'' is needed. For purposes of determining when an oil sample should be taken for the NSPS applicable to utility boilers, section 5.2.2.2 of Method 19 in Appendix A to 40 CFR part 60 relies on a definition of fuel ''lot'' developed by the American Society for Testing and Materials (ASTM). This definition states that ''the lot size of a product oil is the weight of product oil from one pretreatment facility and intended as one shipment (ship load, barge load, etc.).'' In essence, a lot is a single batch of oil that has uniform properties and is purchased from a single supplier and delivered to a buyer. Among those uniform fuel properties are gross calorific value, density, sulfur content, and viscosity. In today's rulemaking, EPA proposes to adopt this definition of a lot of oil for use in the Acid Rain Program.

The Agency also considered whether it is appropriate to keep the current approach of daily manual oil sampling as an option. Although it seems unlikely that facilities would choose daily sampling option if they have the three options of sampling by lot, sampling upon addition of fuel to a storage tank, or continuous sampling, a utility group has requested that EPA retain daily manual sampling as an option. The agency is, therefore, proposing to retain daily manual oil sampling as an option in Appendix D to allow facilities this additional flexibility. An industry representative suggested that EPA could define the oil combusted during a 24-hour period as a lot. For the reasons discussed below and in the section addressing sulfur content, density, and gross calorific values used in calculations, EPA is not incorporating this suggestion in today's proposed rule.

EPA also reconsidered whether it is necessary to require daily composite samples when samples are taken continuously with an automatic sampler. In today's proposal, the Agency is proposing that continuous samples may be composited on a weekly basis rather than daily. The Agency also considered allowing an even longer compositing period, such as a month, but is not proposing this option for the reasons discussed below. A weekly composite sample of oil that is sampled continuously would be an attractive option for a facility that wants the most representative and accurate sulfur content data possible. This also would be a useful option for those few facilities that receive oil via a pipeline, rather than in discrete lots.

Rationale

Facilities wish to be able to perform less frequent fuel sampling in order to save money. From the information EPA has examined over the previous year, the Agency believes that less frequent oil sampling can be technically justified. Based upon information provided by utilities, the sulfur content of a lot of oil varies from sample to sample, with a standard deviation of 0.036 percent S to 0.063 percent S, or 5.62 to 6.85 percent of the average sulfur content for all daily samples between deliveries (see e.g., Docket A–97–35, Item II–D–18). Density and gross calorific value of oil in a lot should vary even less than sulfur content, because sulfur is an impurity in the composition of the fuel and not an essential physical property of the oil, as is density. Furthermore, the difference between the sulfur content, density, gross calorific value, and carbon content of a fuel during the first daily sample after a new delivery is received and the average sulfur content, density, gross calorific value, and carbon content for all daily samples from between two deliveries is extremely small (see Docket A–97–35, Items II–B–18 and II–D–18 for supporting information). Therefore, the Agency expects that the variability of fuel characteristics within a lot is low enough that only a single representative sample is necessary for the lot. Data have indicated that there could be a significant difference in sulfur content between shipments, however (see Docket A–97–35, Items II–B–12, II–B–18 and II–D–18). The Agency believes that differences between lots, which could potentially result in the underestimation of SO_2 emissions, can be dealt with by selecting a conservative sulfur content, density, or gross calorific value that would not be exceeded in any sample, rather than retaining more frequent sampling requirements. Therefore, today's proposal incorporates this approach.

Prior to drafting today's proposed rule revisions, EPA requested comments on removing the option to perform daily manual oil sampling for Appendix D units. At least one utility group expressed interest in retaining the option to allow flexibility. The prime benefit to a facility from continuing to use daily manual sampling would appear to be that the facility could continue to use the same daily operating procedures and that reprogramming of a DAHS would not be necessary. Note that when using the approach of daily manual oil samples, a facility calculates SO_2 mass emissions using the highest sulfur content in the previous 30 daily oil samples. Therefore, this approach requires more frequent analysis than either the proposed weekly composite sample for continuous samples or the proposed sampling by lot, and provides less accurate and more conservative results. The Agency believes it would be simpler and less confusing for both the Agency and for the regulated community to deal with a smaller number of approaches to sampling and calculating SO_2 emissions. However, the Agency is retaining this option since at least some affected utilities want the flexibility to continue to use this option.

EPA also considered the suggestion to define a 24-hour period as a lot in order to allow facilities to continue to perform daily manual sampling. EPA is not proposing this approach because of the added complexity, compared to keeping the current language in section 2.2.4 of Appendix D concerning manual daily sampling of oil. If a lot were defined as an arbitrary 24-hour period, the other requirements in the current rule (e.g., conservative sulfur, gross calorific value, and density values used to calculate SO_2 mass emission rate and heat input rate) would need to be retained to ensure that SO_2 emissions were not underestimated. Furthermore, using the terminology of a ''lot'' for both a delivery and a period of time, while requiring different treatment of sample data from the two different types of ''lots,'' could potentially be confusing. It seems preferable to keep the current language for daily manual samples.

Because the Agency now believes it is appropriate to sample each fuel lot instead of sampling daily, the Agency reconsidered whether daily composite samples are necessary when a facility performs automated continuous sampling. Because continuous samplers take fuel samples multiple times each hour, they are highly representative of the oil being burned. Flow proportional samplers take samples automatically when a certain volume or mass of fuel has passed by, rather than during a particular time period. Generally, automatic samplers take multiple samples each hour; however, only one sample per hour is required under section 2.2.3 of Appendix D of the current rule. Even if the compositing time period is extended, the composite sample will be representative of the sulfur content, density, and gross calorific value of the oil between samples. Therefore, the Agency believes

that the compositing period could be extended from a day to as long a period as a month. However, EPA believes that it is unlikely that any container for taking samples from an automatic sampler would be large enough to accommodate all automatic samples taken during a month. In addition, at least one industry representative suggested that weekly composite samples were appropriate (see Docket A–97–35, Item II–D–30). Therefore, in section 2.2.3 of today's proposed rule, EPA would extend the allowable length of the compositing period for automatic samples to one week. The Agency believes this will make automatic sampling less costly, while taking into account the physical limitations of sampling equipment.

(b) *Gaseous Fuels.*

Background

Section 2.3 of Appendix D, as revised in the May 17, 1995 direct final rule, provides only one approach for sampling gaseous fuel: under section 2.3.1, gaseous fuel sampling must be performed daily. Relatively few utilities perform daily sampling upon gaseous fuels, choosing instead to use a default SO_2 emission rate for pipeline natural gas. In part, this is because the vast majority of gaseous fuel used by power plants is pipeline natural gas. Under section 2.3.2 of Appendix D, facilities may calculate SO_2 mass emissions from pipeline natural gas using a default emission rate instead of performing fuel sampling. Because of the difficulty and potential danger of sampling gaseous fuel, gas sampling is generally conducted by the supplier, rather than by the facility.

Those few utilities combusting gaseous fuels other than pipeline natural gas have expressed concern about the difficulty and expense of daily sampling, particularly in comparison to the value of SO_2 allowances for low SO_2 emissions from relatively clean fuel (see, e.g., Docket A–97–35, Items II–E–11, II–E–20). For gaseous fuels that are delivered in discrete batches or ''lots,'' one would expect the gaseous fuel to behave like an ideal gas; sulfur should be evenly distributed throughout the batch. On this principle, the Ohio Environmental Protection Agency allowed a plant to take propane samples from each discrete delivery, rather than on a daily basis (see Docket A–97–35, Items II–C–14 and II–D–22).

Discussion of Proposed Changes

Today's proposal incorporates three different sampling approaches for gaseous fuels: sampling by lot, daily sampling, and continuous sampling with a gas chromatograph. For gaseous fuel that is delivered in discrete lots, such as liquefied petroleum gas, the gaseous fuel could be sampled either daily or for each lot delivered. Any gaseous fuels other than pipeline natural gas that are not delivered in discrete lots, such as digester gas or sour natural gas pumped directly from a field, would, at a minimum, need to be sampled daily. The samples could be taken either by the supplier or by the facility. However, if the average sulfur content and sulfur variability of such a fuel were too high (i.e., mean sulfur content > 7 gr/100 scf and standard deviation from the mean > 5 gr/100 scf, based on 720 hours of representative historical data), continuous sampling with a gas chromatograph and hourly reporting of sulfur content would be required.

Rationale

The approach of sampling upon a lot or discrete delivery of gaseous fuel is being incorporated into today's proposed rule for the following reasons. The Agency believes that discrete deliveries are sufficiently different from pipeline transmission of fuel that a different sampling approach is appropriate. According to the ideal gas law, all gas within an enclosed volume is mixed with a consistent composition; therefore, a single sample should be representative of all gas in the volume. Although gaseous fuels delivered by lot, such as liquefied petroleum gas, are higher in sulfur content and have a wider range of sulfur contents than pipeline natural gas, they still have relatively low sulfur contents compared to liquid and solid fuels. Thus, less frequent gas sampling appears appropriate, based on the small difference in the accuracy of calculated SO_2 mass emissions. For this same reason, the Agency allowed as-delivered sampling for diesel fuel in the May 17, 1995 direct final rule (see Docket A–94–16, Item II–F–2). Finally, because of the difficulty of sampling gaseous fuels, EPA believes that it is less burdensome and less dangerous if gas sampling is conducted by the gas supplier. It is the Agency's understanding that the sampling for a gas in a discrete delivery or lot is typically conducted once for the lot, rather than on a daily basis. Through a petitioning process, EPA has already allowed one utility to perform sampling upon a lot or discrete delivery of gaseous fuel (see Docket A–97–35, Items II–C–14 and II–D–22).

EPA is proposing to require daily or continuous sampling of gaseous fuels other than pipeline natural gas or the equivalent that are not shipped in discrete lots, such as sour natural gas pumped directly from a field, landfill gas, or digester gas. Such gaseous fuels cannot be guaranteed to be stable in sulfur content. Therefore, proposed section 2.3.3.4 in Appendix D would require a minimum of 720 hours of representative historical data to characterize the sulfur variability of such fuels. For the 720 hours of demonstration data, the mean value and standard deviation of the fuel sulfur content would be calculated. If the mean value does not exceed 7 gr/100 scf (equivalent to about 10 ppm of SO_2 emissions to the atmosphere), daily sampling would suffice. If the mean value is greater than 7 gr/100 scf, however, the variability of the sulfur content would be assessed in terms of the standard deviation. If the standard deviation exceeds 5 gr/100 scf, the sulfur variability would be considered too high and continuous sampling of the fuel with a gas chromatograph would be required. If continuous sampling were required, the owner or operator would have to implement a quality assurance program for the gas chromatograph. A copy of the QA plan would be kept on-site, suitable for inspection. For fuel with a low average sulfur content or a low sulfur variability, daily sampling would be sufficient. However, for gaseous fuel with a higher sulfur content, if the sulfur variability were too great, continuous sampling of the fuel with a gas chromatograph and hourly reporting of sulfur content would be required.

3. Sulfur, Density and Gross Calorific Value Used in Calculations

(a) Fuel Oil.

Background

The hourly SO_2 mass emissions rate due to combustion of oil is calculated using the mass flow rate of oil combusted and a sulfur content value from a sample. If a unit's oil flow rate is measured with a volumetric fuel flowmeter rather than a mass fuel flowmeter, then it will be necessary to determine the mass flow rate of oil from the volume of fuel and a density value from an oil sample. The heat input rate is calculated using the flow rate of oil multiplied by the gross calorific value (GCV) of a sample.

The sulfur content, density, and GCV used to calculate emissions and heat input depend upon the oil sampling method used. Some sampling methods are more accurate than others. For example, for flow proportional or continuous drip sampling, the actual sulfur content from a sample is used to calculate SO_2 mass emissions. However,

when daily manual samples are taken under section 2.2.4 of Appendix D, a facility must use the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples, which is not necessarily the sulfur content of the fuel being burned at any particular time. For units where diesel fuel is sampled upon delivery, section 2.2.1.2 instructs a facility to calculate SO_2 emissions using the highest sulfur content of any oil supply combusted in the previous 30 days that the unit combusted oil. In daily manual sampling and as-delivered sampling, conservative sulfur values are used to avoid the possibility of underestimating SO_2 mass emissions due to variations in sulfur content. Gross calorific values are taken from the most recent sample, rather than using the highest value in the previous 30 days, because, for natural gas, GCV is more consistent than sulfur content.

Today's proposed rule includes changes to the sampling frequency for oil. Therefore, it is also necessary to make corresponding changes to the sulfur content, density, and GCVs to be used in calculations. For example, where oil samples would no longer be taken daily, it would be inappropriate to calculate SO_2 mass emissions based upon a certain number of daily samples. In developing today's proposal, EPA considered what fuel analysis data values for sulfur content, density, and GCV would be appropriate and consistent with the approaches for taking manual samples. The appropriate sulfur content, density, and GCV values were considered for manual samples taken from a storage tank at the facility whenever fuel is added to the tank, for samples taken from each lot before the delivery is transferred from tank trucks or barges, and for samples taken from the fuel supplier's storage tank.

Discussion of Proposed Changes

EPA has re-evaluated the sulfur content, density, and GCVs to be used to calculate SO_2 mass emissions and heat input based upon the new oil sampling approaches. For daily manual oil sampling, a facility would continue to use the highest sulfur content from previous 30 daily samples, and the actual density and GCV. For continuous oil sampling with an automatic sampler, a facility would continue to use the actual sulfur content, density, and GCV. For the two new methods of manual sampling, EPA considered whether conservative or actual values should be used to calculate emissions and heat input. EPA also considered whether the same type of calculational value should be used for sulfur content, density, and GCV. For example, if conservative sulfur content and density values are used to calculate the SO_2 mass emission rate, should a conservative or an actual measured GCV be used to calculate the heat input rate?

For manual samples taken from a storage tank at a plant whenever fuel is added to the tank, EPA considered the following options: (1) using the highest sulfur content and density from the previous three samples, and the actual GCV, (2) using the highest sulfur content from the previous three samples, and the actual density and GCV, (3) using the actual sulfur content, density, and GCV, (4) using the highest sulfur content, density, and GCV from the previous calendar year, and (5) using the maximum sulfur content, density, and GCV allowed by fuel purchase contract with the fuel supplier. The third, fourth, and fifth options are incorporated into today's proposal in section 2.2.4.2. Under this approach, a facility would take a sample from the storage tank whenever fuel is added to the tank. No blending of fuel would be allowed from the time the oil is sampled until the fuel is combusted by the unit. The sample would be analyzed for sulfur content, density, and GCV. Based on the selected option (3, 4, or 5), the appropriate values would then be used to calculate the SO_2 mass emission rate and the heat input rate from the date and hour in which the transfer of oil is complete until the date and hour when oil is again added to the tank.

EPA considered several different options for the case where a facility or its supplier would sample each oil delivery (or the supplier's storage tank) before the fuel is transferred into a tank at the plant. EPA considered whether or not these values needed to be conservative and concluded that there was a real possibility of underestimating SO_2 emissions by using the fuel analysis values from a delivery. The options that EPA considered to avoid the underestimation were: (1) using the highest sulfur content and density from all samples taken from oil combusted during the previous 30 days, and the actual GCV, (2) using the maximum sulfur content, density, and GCV in the fuel purchase contract specifications, (3) using the highest sulfur content, density, and GCV from a sample taken in the previous calendar year, and (4) using the highest sulfur content, density, and GCV ever recorded for the unit. The second and third options are incorporated into today's proposed rule in section 2.2.4.3 of Appendix D.

Under the selected options, a facility or its supplier would need to sample a delivery of fuel before it is transferred into a storage tank. The facility would then need to keep records of the fuel analytical results for three years. The facility would use the conservative value it selected under option (2) or (3), above, in order to calculate the SO_2 mass emission rate and the heat input rate. If an as-delivered sample were ever analyzed and found to have a sulfur content, density, or GCV that exceeded the value being used in calculations (i.e., the contract specification, or the maximum value measured in the previous calendar year), then the new sampled value would be used to calculate the SO_2 mass emission rate or the heat input rate, as follows. For a unit using a default value of the maximum value measured during the previous calendar year, that new sample value would become the new default value and would be reported for the remainder of the current year and the next year, unless superseded by a higher sampled value. For a unit using a default value of a contract specification, the new sample value would continue to be used as the new default value instead of the contract specification value, unless superseded by a higher sampled value or by a new contract.

Rationale

EPA considers continuous sampling and the measurement of fuel from a storage tank at a plant after each addition of fuel to the tank to be highly accurate methods that will be representative of the fuel combusted in a unit. However, if samples are taken from the truck or barge used to ship the fuel, or if samples are taken ''as-delivered,'' the sample values will not necessarily accurately reflect the oil being combusted by the unit at any particular time (see Docket A–97–35, Item II–E–22). For example, a storage tank could contain oil with an average sulfur content of 0.6 percent. Then a new delivery with a sulfur content of 0.4 percent is received and transferred to the tank. The ''as-delivered'' sample value from the delivery truck would underestimate the emissions at that time, since the fuel actually combusted will combine a mixture of the old fuel supply in the storage tank and the new fuel that is added. Thus, a more conservative sulfur value should be used to calculate SO_2 emissions if samples are taken from the delivery containers or from a container used by the oil supplier.

For density and GCV, today's proposal, at the suggestion of some industry representatives, uses conservative values determined by the same method for both parameters (see Docket A–97–35, Item II–E–24). This

has the advantage of being easy to remember and to program. However, if greater accuracy is desired, a facility would always have the option of using actual sulfur content, density, and GCVs if it took samples from its storage tank after each addition of fuel to the tank, or if it took continuous, automatic samples.

EPA considered which conservative values would be appropriate for sulfur, density, and GCV. EPA at first considered using the maximum value from all oil supplies combusted in the previous 30 days. This is similar to the current wording of section 2.2.1.2 of Appendix D for calculation of SO_2 emissions from diesel fuel as-delivered sampling. However, in the process of implementing this provision of part 75, EPA found this wording was somewhat confusing and issued policy guidance to clarify section 2.2.1.2 of Appendix D (see Docket A–97–35, Item II–I–9, Policy Manual, Question 2.9). This policy essentially directs facilities to keep track of the amount of fuel used as well as its sulfur content. Because of the more complicated nature of this accounting, some industry representatives suggested that it would be simpler to use a conservative default value that would not require tracking fuel usage (see Docket A–97–35, Item II–E–24). Of the default values considered, EPA felt that the most appropriate default values would be the maximum values established by agreement with the fuel supplier through a contract or the maximum measured value from all samples in the previous calendar year. Contractual limits should be higher than or equal to the actual sulfur content, density, or GCV. Because not all units would necessarily have a fuel contract limiting oil sulfur content, density, or GCV, EPA is also proposing to provide the option of using the maximum oil sulfur content, density, or GCV in the previous calendar year.

The Agency also considered whether the current provisions of 2.2.4 of Appendix D should be retained for calculation of SO_2 emissions using the highest sulfur from the previous 30 daily samples when performing daily manual sampling. As discussed above in Section III.P.2(a) of this preamble on oil sampling frequency, the Agency is proposing to retain the option as requested by at least one utility representative.

(b) *Gaseous Fuels.*

Background

The vast majority of Acid Rain units which burn gaseous fuels combust pipeline natural gas. Section 2.3.2 of Appendix D contains a provision for calculation of SO_2 mass emissions from pipeline natural gas using a default SO_2 emission rate in lb/mmBtu and the heat input rate of pipeline natural gas. However, if a facility or its supplier is sampling gaseous fuel for sulfur content, either because it is not pipeline natural gas or because the facility chooses to use a sampled value, then Appendix D requires the facility to calculate the SO_2 mass emission rate using the sulfur content of the sample and the volume of gas combusted, and to calculate the heat input using the GCV of the sample and the volume of gas combusted (see Equations D–5 and F–20). Because of the nature of gaseous fuels, they are always measured with a volumetric fuel flowmeter. The formulas for calculating the SO_2 mass emission rate and the heat input rate use volume directly and do not require information on gas density. The current provisions of Appendix D allow a facility to calculate the SO_2 mass emission rate and the heat input rate using the actual value from a daily sample of gaseous fuel.

When the provisions of section 2.3 of Appendix D were added to part 75 in the May 17, 1995 direct final rule, EPA presumed that virtually every utility combusting gaseous fuel was combusting pipeline natural gas. However, the Agency found that utilities were combusting other types of gaseous fuels. One utility submitted a monitoring plan and a certification application for fuel flowmeter monitoring systems that indicated the utility was also using propane liquefied petroleum gas (LPG) (see Docket A–97–35, Item II–D–6). The utility indicated that it wished to use the default emission rate factor reserved for pipeline natural gas in its monitoring plan and later petitioned the Agency specifically for permission to use the default emission rate factor of 0.0006 lb/mmBtu. In conversations with utility staff, EPA found that the utility wanted to avoid the expense of additional daily samples and the trouble of entering daily sulfur values manually into its data acquisition and handling system (see Docket A–97–35, Items II–E–11, II–E–20). The Agency eventually approved a revised petition for the utility that allowed the utility to take propane samples from each discrete delivery, rather than on a daily basis, where the utility calculates sulfur dioxide emissions from propane by using the highest sulfur content recorded during the previous 365 days and reports these data in its quarterly electronic data report (see Docket A–97–35, Items II–C–14 and II–D–22).

The Agency found that there were also some utilities burning gaseous fuels that were by-products of an industrial process (see Docket A–94–16, Item II–D–71). EPA had concerns that such ''digester gas'' might have a more variable sulfur content than pipeline natural gas, since the gaseous fuel would begin with a higher sulfur content than pipeline natural gas and would not necessarily go through a process that would reduce and stabilize the sulfur content.

Discussion of Proposed Changes

In today's proposed rule, the provisions for sampling gaseous fuels are found in section 2.3.1 of Appendix D. For gaseous fuels that are delivered in discrete lots, a facility would use conservative values for sulfur content and GCV to calculate the SO_2 mass emission rate and the heat input rate. For the sulfur content value, the highest sampled sulfur content from the previous calendar year or the maximum value allowed by contract would be used to calculate the SO_2 mass emission rate. For GCV, the highest of all sampled values in the previous calendar year or the maximum value allowed by contract would be used to calculate the heat input rate. If, for any gas sample, the assumed sulfur content or GCV were exceeded, the sampled value would become the new assumed value. For units using the contract value, the sampled value would continue to be used unless a new (higher) contract specification were put in place or unless an even higher sampled value is obtained. For units using the maximum value from the previous year, the sampled value would continue to be used for the remainder of the current year and for the next calendar year unless it was superseded by an even higher sampled value.

For any gaseous fuel where daily fuel sampling is required, a facility would use the highest sulfur in the previous 30 daily samples. For gaseous fuels other than pipeline natural gas, where daily sampling of sulfur content is required, the highest GCV from the previous 30 daily samples would be used. For pipeline natural gas, where monthly sampling of GCV only is required, the actual measured GCV, the highest of all sampled values in the previous calendar year, or the maximum value allowed by contract would be used.

For a gaseous fuel that is not produced in batches and that has a relatively high sulfur content and a high sulfur variability, continuous sampling with a gas chromatograph would be required. Sulfur content would be reported as actual measured hourly average values. The GCV would also be determined on an hourly basis, or,

alternatively, the highest value in the previous 30 unit operating days could be reported.

Rationale

For gaseous fuel supplied in discrete deliveries, EPA is proposing to take the same approach as for fuel oil that is being delivered to a plant by barge or truck. EPA has already approved this approach with one utility that combusts liquefied petroleum gas (see Docket A–97–35, Items II–C–14 and II–D–22). Because a discrete delivery of gaseous fuel would be maintained in an enclosed chamber with a relatively constant temperature and pressure, one would expect the gaseous fuel to behave like an ideal gas. Thus, sulfur and other constituents of the fuel should be evenly distributed throughout the delivery of fuel. Using conservative values to calculate the SO_2 mass emission rate and the heat input rate should account for any variability between deliveries. Furthermore, this reduces the number of changes that would be made to a data acquisition and handling system to add fuel supply data.

For gaseous fuel other than pipeline natural gas, where daily fuel sampling is required, EPA considered leaving unchanged the current provisions of section 2.3.1 of Appendix D that would allow a utility to use the actual value from a day's sample to calculate the SO_2 mass emission rate and the heat input rate. However, the Agency believes that it is appropriate to change the sulfur content value to be a somewhat conservative historical value. This is because the Agency has concerns that there may be some gaseous fuels other than natural gas, such as digester gas, that may have significant variability in their sulfur content over the course of a day or a longer period of time. This might result in the underestimation of the SO_2 mass emission rate.

In the case of fuel oil, some industry representatives suggested it was simplest to determine the appropriate conservative values for sulfur content, density, and GCV by the same method (see Docket A–97–35, Item II–E–24). With one exception (for fuels with relatively high sulfur content and high sulfur variability), today's proposal follows this suggestion for gaseous fuels. The proposal uses the highest sulfur content and the highest GCV from the previous 30 daily samples. This is currently the procedure used to determine the sulfur value used in calculations from daily manual oil samples. Since this algorithm for daily manual oil sample calculations is already being used by many software programmers, it is a good conservative value to use for daily samples in this case. The Agency notes that currently, the heat input is calculated using the actual sampled GCV and that this change would require software reprogramming for units where gaseous fuel is sampled daily. However, for pipeline natural gas that is sampled monthly for GCV, facilities could continue to use the actual GCV measured in a monthly sample. The other two options are more conservative and would require software changes. The Agency requests comment on the proposal to use the more conservative GCV value to determine the heat input rate for gas combustion when gaseous fuel is sampled daily (which differs from the current procedure in section 2.3.1.3 of Appendix D and section 5.5.2 of Appendix F).

For gaseous fuel that has a relatively high sulfur content and high sulfur variability, daily sampling is not considered adequate to ensure that SO_2 emissions will not be underestimated. Therefore, for such fuels, continuous sampling with a gas chromatograph and hourly reporting of sulfur content would be required. For GCV, which is expected to be less variable than sulfur content, either the actual hourly measured value or the highest GCV value obtained in the last 30 unit operating days could be reported.

4. Missing Data Procedures for Sulfur, Density, and Gross Calorific Value

Background

(a) *Fuel Oil.* The May 17, 1995 direct final rule included missing data procedures for missing analytical information on sulfur content, density, and GCV in section 2.4 of Appendix D. These procedures are based on a daily sampling frequency. For example, missing sulfur content, density, or GCV data are to be calculated using the highest measured sulfur content, oil density, or GCV during the previous thirty days when the unit burned oil. This was intended to mean that the substitute data values are to be based on the previous thirty daily oil samples for which data are available.

In order to ensure that a DAHS is capable of implementing the missing data procedures required by the rule, § 75.20(c)(7) and § 75.20(g)(1)(ii) require testing of each DAHS. EPA issued policy guidance discussing how facilities should report the results of these tests for units measured with fuel flowmeters. This policy guidance provided a form checklist that facilities could use to show the results of their own tests of the missing data substitution procedures (see Docket A–97–35, Item II–I–9, Policy Manual, Question 15.9). Some utilities objected to testing the DAHS missing data procedures on the grounds that they should never miss sample data. In part, this would be because the facility is required, under section 2.2.5 of Appendix D, to split its sample and keep a portion. One utility offered to substitute the maximum potential sulfur content, which would require less complicated DAHS programming than using the maximum sulfur content of the previous 30 daily samples.

(b) *Gaseous Fuels.* Section 2.4.1 of Appendix D, as revised by the May 17, 1995 direct final rule, provides missing data substitution procedures for missing sulfur data from daily samples of gaseous fuel. The DAHS is required to substitute the highest measured sulfur content recorded during the previous 30 days when the unit combusted gaseous fuel. As for oil, this was intended to be the highest sulfur value from the previous 30 daily samples with available sulfur values. Section 2.4.2 of Appendix D requires the substitution of the highest measured GCV recorded during the previous three months that the unit burned gaseous fuel when data are missing from a monthly gaseous fuel sample. As for fuel oil, the missing data procedures for gaseous fuels are linked to the frequency of fuel sampling.

A utility indicated to EPA that because it receives gas sampling information from its supplier, it should never have missing data for GCV. The utility suggested that it should not have to go to the expense of programming its DAHS for missing data procedures that should never need to be used. This argument was similar to that used by another utility when referring to missing data procedures for manual samples of fuel oil taken upon each delivery.

Discussion of Proposed Changes

EPA proposes to revise the missing data substitution procedures for both fuel oil and gaseous fuel, in order to simplify them. For any instance in which the sulfur content, GCV, or density value is missing, the maximum potential value would be reported until the results of a subsequent valid sulfur content analysis, GCV determination, or density measurement are obtained. The proposed appropriate maximum potential values are specified in the table below. The default values for sulfur content, GCV, and density of residual oil and diesel fuel were taken from handbook values (see Docket A–97–35, Item II–A–7). The default maximum sulfur content values for gaseous fuel are consistent with the maximum sulfur content allowed under

the definition of natural gas and the *de facto* maximum sulfur content of pipeline natural gas, based on the proposed definition. Thus, any gas with a sulfur content that did not allow it to qualify as pipeline natural gas (i.e., greater than 0.30 gr/100 scf) but still allowed it to be measured following Appendix D procedures (i.e., total sulfur content not exceeding 20.0 gr/100 scf) would have a default maximum potential sulfur content of 20.0 gr/100 scf. The default values for GCV of gaseous fuels were taken from handbook values (see Docket A–97–35, Item II–I–1). For pipeline natural gas, it is assumed that the gas is primarily methane (GCV of 1050 Btu/scf) with a small amount of other hydrocarbons with a higher GCV (see Docket A–97–35, Item II–E–19). For other gaseous fuels, it is assumed that they are primarily butane (GCV of 2100 Btu/scf), the hydrocarbon gas with the highest GCV of gases commercially used for fuel.

MAXIMUM POTENTIAL DEFAULT VALUES FOR SULFUR CONTENT, DENSITY, AND GCV DATA

Parameter	Fuel	Maximum potential default value
Sulfur content	residual oil	3.5 percent by weight.
	diesel fuel	1.0 percent by weight.
	pipeline natural gas	0.30 gr/100 scf.
	gaseous fuels with sulfur content greater than pipeline natural gas.	20.0 gr/100 scf.
GCV/heat content	residual oil	19,500 Btu/lb.
	diesel fuel	20,000 Btu/lb.
	pipeline natural gas	1100 Btu/scf.
	gaseous fuels with sulfur content greater than pipeline natural gas.	2100 Btu/scf.
Oil Density	residual oil	8.5 lb/gal,
	diesel fuel	7.4 lb/gal.

Rationale

(a) *Fuel Oil.* It seems possible that a facility might occasionally miss a sample taken with an automatic sampler, and thus, would have missing data. Therefore, today's proposal includes a provision for substitution of missing sulfur content, density, and GCV data from continuous, automatic sampling.

Based upon comments from some utilities, it seems relatively unlikely that both a facility and its supplier would miss performing a sample during a delivery. Both a facility and its fuel supplier will want to verify that the fuel delivered is actually supplying the heat content that it is supposed to, either under a contract or a fuel specification; thus, both a facility and its fuel supplier will have an incentive to ensure sampling takes place for a delivery. Furthermore, if samples taken by a facility are split, then there should generally be the ability to provide analytical data for that fuel, even if test results were somehow lost. Because the event of missing fuel samples is unlikely for as-delivered samples, EPA believes that it would be appropriate to establish a simple, conservative value that could easily be substituted in a data acquisition and handling system. This would be easier to program than using historical values that require tracking fuel usage over an extended period of time.

EPA is specifically proposing the most conservative (maximum potential) values for missing data purposes. This would ensure that substituted missing data values would be less advantageous to a facility than taking samples and using sulfur content, density, and GCV data from samples. In addition, several utilities suggested to EPA that this was a reasonable approach (see Docket A–97–35, Item II–E–24).

(b) *Gaseous Fuels.* As mentioned previously, gas sampling is generally performed by fuel suppliers because of the difficulty and potential danger of opening up a pressurized pipe containing a highly flammable gas. It seems extremely unlikely that a fuel supplier would not have information available on the sulfur content or GCV of gaseous fuel, since industrial customers will purchase fuel or agree to a contract based upon these characteristics. The exception to this might be gaseous fuel manufactured through an industrial process that is not produced specifically for sale as a fuel, such as digester gas. In today's proposed rule, EPA is using the same reasoning as above for missing manual fuel oil sample data and is using the same basic substitution approach for missing sulfur content and GCV data for gaseous fuel.

EPA considered keeping the existing missing data substitution procedures from sections 2.4.1 and 2.4.2 of Appendix D for missing data from gaseous fuel. This would have the advantage of requiring no reprogramming of software for facilities already following the existing procedures. EPA also considered using the maximum sulfur content or GCV from the previous calendar year, the same procedure proposed in today's rule for calculation of SO_2 mass emission rate or heat input, for discrete deliveries of gas or for manual samples of oil taken from a delivery truck or barge. However, using the proposed maximum value would require little reprogramming and would greatly simplify the missing data procedures. In policy guidance, the Agency has indicated it would accept a simplified DAHS for units using the procedures of Appendices D and E. In particular, these policies endorse manual entry of fuel analytical data, simplified missing data procedures for fuel flowmeters, and a DAHS that uses commercial spreadsheet software instead of a specialized custom software for purposes of part 75 (see Docket A–97–35, Item II–I–9, Policy Manual, Questions 14.72 and 14.73). In keeping with the policy of allowing Appendices D and E units to use commercial spreadsheet software, EPA has proposed what it believes to be the simplest possible missing data substitution procedure for missing sulfur content and GCV data. In addition, using the proposed maximum potential sulfur content or GCV would ensure that substituted missing data values are more conservative than the values normally used to calculate the SO_2 mass emission rate and the heat input rate.

5. Installation of Fuel Flowmeters for Recirculation

Background

The current provisions of section 2.1.1 of Appendix D require the use of an additional ''return'' fuel flowmeter when some fuel is recirculated, i.e., initially sent toward a unit and then diverted away from the unit without being burned. This additional fuel flowmeter is required, regardless of the amount of fuel being diverted.

At least one utility has requested to use only the fuel flowmeter measuring fuel leaving the oil tank without a second fuel flowmeter to measure any fuel diverted away by the recirculation fuel line. The utility argued that using a single fuel flowmeter would result only in the overestimation of SO_2 emissions, since the utility would measure a larger amount of fuel usage. This would allow the facility to avoid the expense of installation, certification, and quality assurance testing on a fuel flowmeter on the recirculation fuel line. Since the proportion of fuel being recirculated was minimal, the utility was willing to use a more conservative SO_2 emissions calculation in exchange for devoting fewer resources for the testing and maintenance of the recirculation line fuel flowmeter.

Discussion of Proposed Changes

In today's proposal, EPA proposes to allow facilities to use only a fuel flowmeter on the main fuel line from the oil tank if the amount of oil recirculated is demonstrated to be less than 5.0 percent of total fuel usage for each hour during the year.

Rationale

EPA believes that it is reasonable not to require installation, certification and quality assurance of secondary fuel flowmeters in cases where the amount of fuel to be combusted is a small proportion of the total fuel used, and where knowing the exact volume of the recirculated fuel makes little difference in the calculation of emissions and heat input. EPA has allowed one utility to use an estimate of the maximum oil usage at start-up, rather than requiring the utility to install a return line oil flowmeter to measure the startup fuel flow rate.

At first, EPA considered making the installation of a fuel flowmeter on a recirculation fuel line optional. Presumably, if the cost in lost SO_2 allowances were greater than the cost of installing and maintaining a fuel flowmeter, then a facility would choose to use a fuel flowmeter on the recirculation fuel line. However, many fuel flowmeters used under Appendix D for determining the SO_2 mass emission rate and the heat input rate are also used to estimate the NO_X emission rate in lb/mmBtu under Appendix E to part 75. The Appendix E procedures estimate hourly NO_X emission rates using a correlation between measured NO_X emission rates and heat input rates. The correlation is established during a testing period. Therefore, subsequent to the test period, if the hourly heat input values should become less accurate, it could result in the estimated NO_X emission rates becoming less accurate. Such loss in accuracy could occur if the heat input rates during the initial testing period were based upon subtraction of measured volumes or masses of recirculated fuel from the total fuel flow rates, and then the facility later began estimating, rather than measuring, the recirculated fuel volumes or masses. The potential inaccuracy would increase if the proportion of recirculated oil to the total flow rate of oil varies over time. The NO_X emission rate can sometimes increase with increases in the heat input rate and can sometimes decrease with increases in the heat input rate, depending on the particular type of boiler; in addition, when certain types of control equipment are installed, the NO_X emission rate may not have any relationship with the heat input. Thus, an overestimation of the heat input rate would sometimes result in the overestimation and sometimes result in the underestimation of the NO_X emission rate under Appendix E. For these reasons, EPA believes that there needs to be some limits on the cases where a facility can choose not to use a return fuel flowmeter.

In today's proposed rule, EPA is proposing that a facility may choose to use only a fuel flowmeter on the main fuel line from the oil tank and not install a return meter in those cases where the previously measured proportion of oil from the recirculation line is less than or equal to 5.0 percent of the unit's total oil usage during each hour of the year. EPA believes that an error of 5.0 percent in the heat input rate should be small enough that it will not significantly affect accounting for the NO_X emission rate under Appendix E. An analysis of emissions data from a gas-fired Appendix E unit with a higher than average NO_X emission rate for gas (0.157 lb/mmBtu) showed that a 5.0 percent increase in heat input would change the quarterly average NO_X emission rate by only 3.17 percent (0.152 vs. 0.157 lb/mmBtu) (see Docket A–97–35, Item II–B–19). At the same time, EPA believes that an average proportion of 5.0 percent of total fuel usage should provide relief for the most extreme situations where it might cost more to perform quality assurance testing on a return fuel flowmeter than the value of the allowances saved by monitoring with the return flowmeter.

The Agency also considered whether it would be more appropriate to determine the proportion of recirculated fuel on an hourly average basis or on an annual average basis to determine if the returned fuel was less than 5.0 percent of total fuel usage. The Agency concluded that the proportion of fuel could be determined only if a return fuel flowmeter were already installed on the recirculation fuel line. Thus, there would appear to be little advantage to basing the proportion of fuel on an annual basis. Hourly average fuel flow rate would also be more directly related to the heat input rate used to calculate hourly NO_X emission rate under Appendix E. EPA notes this is not fully consistent with the objective of revising this provision, i.e., to exempt facilities from installation and operation of additional fuel flowmeters. Therefore, the Agency believes it is better to base the reduced fuel flow rate monitoring requirement either on actual historical fuel flowmeter data or on some other method, as yet unknown, that would yield a reasonable estimate of the average proportion of fuel recirculated to the total amount of fuel used. At this time, the Agency is unaware of what other methods could provide a reasonable estimate of the average proportion of fuel recirculated to the total amount of fuel used, either on an hourly or an annual basis. Accordingly, the Agency would allow facilities to suggest methods through the petitioning process of § 75.66.

6. Fuel Flowmeter Testing

(a) *Fuel Flowmeter Accuracy Tests.*

Background

Sections 2.1.5 and 2.1.6 of Appendix D, as revised by the May 17, 1995 direct final rule, refer to calibration and recalibration of fuel flowmeters. Section 2.1.5.2 gives procedures for a test of the flowmeter accuracy by comparing a candidate flowmeter against another flowmeter that has already been calibrated according to specified procedures. If a flowmeter does not meet the specified accuracy, then it would need to be recalibrated by adjusting it, then retested to ensure it is reading accurately.

Some utilities have found confusing the terminology of ''calibration'' for a test that compares measurements from two different flowmeters. Generally, the

term ''calibration'' is used to refer to adjustments made to a flowmeter to ensure it is reading accurately. However, the type of test described in section 2.1.5.2 is more like a relative accuracy test audit than a calibration, in that it checks the flowmeter accuracy by comparing the fuel flowmeter readings against readings from an outside standard.

Discussion of Proposed Changes

To alleviate the confusion surrounding flowmeter testing, today's proposal introduces the term ''flowmeter accuracy test.'' This terminology is used in sections 2.1.5 and 2.1.6 of Appendix D.

Rationale

EPA believes that the term ''flowmeter accuracy test'' more clearly reflects the nature of the test that is performed. Introducing this new term also will clarify that the word ''calibration'' refers to flowmeter adjustments, rather than to a comparative test between a candidate flowmeter and a reference meter.

(b) *Methods for Fuel Flowmeter Accuracy Testing.*

Background

Section 2.1.5.1 of Appendix D, as revised by the May 17, 1995 direct final rule, includes a list of standards and procedures that may be used to determine if a flowmeter is sufficiently accurate for use under the Acid Rain Program. However, because of the large number of different brands and kinds of fuel flowmeters, there are also many manufacturers' procedures that are not explicitly permitted under part 75. Consequently, many Acid Rain certification applications for units with fuel flowmeters have contained petitions under §§ 75.23 and 75.66 for approval of other fuel flowmeter testing procedures. Among those methods was AGA Report No. 7 for turbine flowmeters. This method was incorporated by reference into part 75 in the November 20, 1996 final rule. In addition, another standard method that EPA approved through petitions is American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the *Manual of Petroleum Measurement Standards,* October 1988 edition (see reproduction of this document in Docket A–97–35, Item II–D–10 (Attachment B)).

In the process of implementing part 75, many utilities have commented on the problems of testing and calibrating fuel flowmeters. Unlike CEMS or stack flow monitors, it is not always possible to perform an accuracy test with the fuel flowmeter remaining in the pipe where it is installed. Utilities have stated that certain fuel flowmeters are extremely difficult to remove, send out for testing, recalibrate, and then reinstall (see Docket A–97–35, Item II–E–22). In addition, removing a fuel flowmeter from in-line may require stopping flow of the fuel and possibly shutting down the unit, with negative economic consequences (see Docket A–97–35, Item II–E–8). In addition, if a facility needs to operate a unit while the flowmeter is being tested at a laboratory, then no flow data will be available for the fuel measured by the flowmeter unless the facility has a backup fuel flowmeter. Utilities have petitioned for alternative quality assurance procedures for fuel flowmeters in order to avoid the inconvenience and expense of removing the fuel flowmeter and testing it (see Docket A–97–35, Item II–D–9). Because of this, the Agency has been evaluating various ways of testing a fuel flowmeter in-line (that is, still installed in the pipe in its regular position).

Some utilities have suggested that an alternative way to check fuel flowmeter accuracy would be to compare over time the ratio of the fuel flowrate to unit output (''load''), measured either in electrical generation in MWe or in steam flow in 1000 lb/hr (see Docket A–97–35, Item II–E–21). A fuel flow-to-load comparison could be used to determine if fuel flowmeter readings are still similar to the readings obtained the last time the fuel flowmeter was tested against an outside method. A significant change in the amount of fuel used at a load level would call into question the validity of fuel flow readings from a flowmeter. A fuel flow-to-load comparison could provide this check without removal of the fuel flowmeter from its installed location, which would be of considerable benefit to facilities.

Discussion of Proposed Changes

EPA is proposing to incorporate by reference the standard: American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the *Manual of Petroleum Measurement Standards.* The Agency also specifically requests comment on any other voluntary consensus standards from standard setting organizations, such as API, AGA, ASME, or ISO, that would be appropriate for incorporation by reference into part 75. Any suggested methods should also be submitted to the Agency as part of the comments to assist in the Agency's evaluation.

Section 2.1.7 of Appendix D to today's proposed rule includes provisions for an optional, supplemental quality assurance test for fuel flowmeters using a ratio of the fuel flow rate and the unit load. The fuel flow rate-to-load ratio comparison test would provide an additional way to meet the requirement to periodically test fuel flowmeter accuracy. This test would serve as a supplement to more rigorous fuel flowmeter tests. These more rigorous tests include the standards incorporated by reference under section 2.1.5.1 of Appendix D that require the fuel flowmeter to be taken out of line and shipped to a laboratory, and the ''master meter'' comparison procedures under section 2.1.5.2 of Appendix D. For orifice-, nozzle-, and venturi-type flowmeters, the more rigorous tests would include an inspection of the primary element and an accuracy test on the transmitters or transducers. If a facility performed and passed regular quarterly fuel flow-to-load ratio testing, then it would need to perform the more rigorous checks on monitor performance only once every 20 calendar quarters (five years).

The fuel flow-to-load ratio test would require a facility to establish a baseline period from a period of time when the fuel flowmeter is known to be operating properly. After establishing this baseline of accurate fuel flow data (or heat input rate data), a facility would calculate the fuel flow-to-load ratio (or ''gross heat rate'' (GHR)) during the baseline period. In each ''flowmeter operating quarter'' that the fuel flowmeter operates after the baseline period is completed, the facility would calculate the fuel flow-to-load ratio (or GHR) for each hour the fuel flowmeter is used to report data. The facility would compare the hourly fuel flow-to-load ratio (or GHR) to the fuel flow-to-load ratio (or GHR) during the baseline period in order to calculate the absolute value of the percentage difference for each hour. Next, the facility would calculate the average percentage difference for the quarter. If the percentage difference exceeded the specified limits for the test, the fuel flowmeter would fail the test. The key elements of the fuel flow rate-to-load evaluation are discussed in the following paragraphs.

(1) *Use of Gross Heat Rate-to-Load Ratio.* Today's proposed rule would allow a facility the option of calculating either the ratio of the fuel flow rate to the gross generation in MWe or the steam flow rate in thousands of pounds of steam per hour (''fuel flow-to-load ratio'') or the ratio of the heat input rate to the gross generation in MWe or the steam flow rate in thousands of pounds of steam per hour (''GHR''). In order to allow a meaningful comparison, a facility would use one of these two ratios consistently, both in calculating

an initial baseline ratio and in calculating hourly ratios during a particular quarter. Equations D–1c and D–1e describe the calculation of the fuel flow-to-load ratio for the baseline period and for hourly values during a calendar quarter, respectively. For the GHR, the respective equations are Equations D–1d and D-1f. These equations are found in proposed sections 2.1.7.1 and 2.1.7.2 of Appendix D.

(2) *Baseline Period for Fuel Flow-to-Load Ratio.* The provisions for calculating the baseline fuel flow-to-load ratio or gross heat rate are found in section 2.1.7.1 of today's proposed rule. EPA is proposing that the owner or operator of a facility would establish a baseline of fuel flow rate (or heat input rate) data following a flowmeter accuracy test under either section 2.1.5.1 or 2.1.5.2 of Appendix D, or following both a transmitter or transducer accuracy test under section 2.1.6.1 of Appendix D and an inspection of a primary element for an orifice-, nozzle-, or venturi-type fuel flowmeter under section 2.1.6.6. Throughout section 2.1.7 of today's proposed rule, these are referred to as ''the most recent quality assurance procedure(s).'' The baseline period of fuel flow rate (or heat input rate) data for a fuel flowmeter to be tested under section 2.1.7 would use the first 168 hours of quality assured data measured by that flowmeter following the most recent quality assurance procedure(s) for which: (1) only the fuel measured by that fuel flowmeter is combusted (i.e., no co-firing of fuels occurs); (2) the load is relatively stable and not ''ramping'' rapidly up or down; and (3) the load is sufficiently above the minimum safe, stable operating load (unless low-load operation is normal for the unit).

Today's proposal includes a limit to the length of time over which the baseline period could extend. The baseline period of 168 hours could not extend for longer than the end of the second calendar quarter following the calendar quarter in which the most recent quality assurance procedure(s) was performed. For orifice-, nozzle-, and venturi-type fuel flowmeters, two quality assurance procedures would be required: both a transmitter or transducer accuracy test under section 2.1.6.1 of Appendix D and an inspection of a primary element, such as an orifice plate. For practical purposes, this means that the transmitter or transducer accuracy test and the primary element inspection would have to be completed either in the same calendar quarter or in consecutive calendar quarters. If there were not 168 hours of quality-assured fuel flowmeter data from hours when a single fuel is combusted, then the fuel flowmeter would not be allowed to be tested using the fuel flow-to-load ratio as a supplement to other quality assurance tests.

The 168 hours of quality-assured fuel flowmeter data next would be averaged and divided by the average load, in megawatts or 1000 lb steam/hr, during the same 168 hours to determine the baseline fuel flow-to-load ratio (see Equation D–1c). Alternatively, the facility could instead calculate the gross heat rate by averaging hourly heat input rate during the 168 hours of the baseline period and by dividing the average heat input rate by the average load during the same 168 hours (see Equation D–1d).

In cases where the fuel flowmeter is located on a common pipe header, one fuel flow rate measurement could be associated with the load from several units that receive fuel from the common pipe header. In order to analyze the fuel flow-to-load ratio for a flowmeter on a common pipe header, the load from all units receiving fuel from the common pipe header would have to be combined for each hour, averaged over the baseline period of 168 hours, and compared to the average fuel flow rate during the baseline period. If a single unit receives fuel from multiple pipes, each pipe with its own fuel flowmeter, then the flow rates from all fuel flowmeters would have to be added together to obtain the average fuel flowrate for the unit to be divided by the unit load.

(3) *Data Preparation and Analysis.* In each flowmeter operating quarter following the final quarter of the baseline period, all hourly fuel flowmeter data would be compared to the load. A flowmeter operating quarter would be a calendar quarter in which the unit combusts the fuel measured by the fuel flowmeter for at least 168 hours. For each hour in which the fuel is combusted, the owner or operator would calculate the fuel flow-to-load ratio (or GHR) (see Equation D–1e for the fuel flow-to-load ratio and Equation D–1f for the GHR). Hourly fuel flow rates on common pipe headers would be compared to the sum of the loads from all units receiving fuel from the common pipe header. For units with multiple pipes and multiple fuel flowmeters, the total hourly fuel flow rate for the fuel would be compared to the unit load.

Next, the facility would compare the hourly fuel flow-to-load ratios (or GHRs) to the baseline fuel flow-to-load ratio (or GHR). The absolute value of the percentage difference would be calculated for each hour using Equation D–1g. Then the facility would calculate the average value of the percentage difference for the quarter, using each hourly percentage difference in Equation D–1h.

The quarterly average of the hourly percentage difference values next would be compared to the limitation. For either the fuel flow-to-load ratio or the GHR, Ef, the quarterly average of the hourly percentage difference values would need to be no greater than 10.0 percent, unless the average of the hourly loads used for the analysis was ≤ 50 MWe (or ≤ 500 klb/hr of steam), in which case the limit on Ef would be 15.0 percent. If a fuel flowmeter were to fail to meet this limit when using all data in the flowmeter operating quarter, then the facility would have the option of excluding certain hours. Otherwise, a failure to meet the 10.0 percent (or 15.0 percent, if applicable) limit would be considered a failure of the fuel flow-to-load ratio test.

(4) *Optional Data Exclusions.* As mentioned above, if a fuel flowmeter's data would not meet the 10.0 percent (or 15.0 percent, if applicable) limit on the quarterly average of the percentage difference values, then a facility could opt to exclude certain hours of unrepresentative fuel flow rate (or heat input rate) data and then reanalyze the smaller set of data. The types of data that EPA proposes as non-representative would be the same as the hours excluded during the baseline period, including: (1) hours when the unit combusts multiple fuels measured by multiple fuel flowmeters, such as co-firing of gas and residual oil or co-firing of residual oil and diesel fuel; (2) hours when the unit load is rapidly rising or falling, sometimes referred to as ''ramping,'' to such a degree that the load in a given hour differs by more than ± 15.0 percent from the load during either the previous hour or the hour afterwards; or (3) hours in which the unit load is in the lower 10.0 percent of the unit's operating range, unless operation at those low levels is considered normal for the unit. The facility would proceed to analyze the remaining quarterly fuel flow rate or heat input rate values, provided that there are at least 168 hours remaining for the quarter after excluding non-representative hours. If less than 168 representative hours remained after excluding the allowable hours, then a flow-to-load or GHR test would not be required for that flowmeter for that flowmeter operating quarter. If the fuel flowmeter data still failed to meet the 10.0 percent (or 15.0 percent, if applicable) limit on the quarterly average of the percentage difference values after excluding the allowable

hours, the flowmeter would fail the fuel flow-to-load ratio test.

(5) *Consequences of Failing Fuel Flow-to-Load Ratio or GHR Tests.* There would be two primary consequences of failing a fuel flow-to-load ratio or a GHR test. First, the data from the fuel flowmeter would no longer be considered quality-assured. Thus, the facility would need to invalidate data from the fuel flowmeter following the test. Proposed section 2.1.7.4 of Appendix D specifies that the missing data procedures of section 2.4.2 of Appendix D would be used to substitute for the invalid data (unless a different fuel flowmeter is available that has been tested for accuracy and has been demonstrated to meet the accuracy specification), beginning with the first hour the fuel measured by the fuel flowmeter is used during the quarter following the flowmeter operating quarter in which the meter fails the fuel flow-to-load ratio test. Second, in order to establish that the fuel flowmeter is again operating properly and providing quality-assured data, the facility would perform a fuel flowmeter accuracy test according to sections 2.1.5.1 or 2.1.5.2 of Appendix D or, for orifice-, nozzle-, and venturi-type flowmeters, a transmitter or transducer accuracy test according to section 2.1.6.1 of Appendix D. In addition to the transmitter or transducer test, orifice-, nozzle-, and venturi-type fuel flowmeters would need to be further tested following a failed flow-to-load or GHR test in order to ensure that the problem causing the failure of the fuel flow-to-load ratio was a problem with the transmitters or transducers.

Once the orifice-, nozzle-, or venturi-type flowmeter has been recalibrated and passes a transmitter or transducer accuracy test according to section 2.1.6.1 of Appendix D, the facility would perform a shortened version of the fuel flow-to-load ratio test. The shortened version of the test would use six to twelve hours of data following the passed transmitter or transducer accuracy test. If the fuel flowmeter passed the abbreviated fuel flow-to-load ratio test, then its data would be considered valid, beginning with the time and date of the passed transmitter or transducer accuracy test. However, if the fuel flowmeter were to fail the abbreviated fuel flow-to-load ratio test, then it would be necessary for the facility to inspect the primary element for corrosion or damage. Furthermore, data would be considered invalid until the orifice-, nozzle-, or venturi-type fuel flowmeter passes an inspection of the primary element. Although data from the flowmeter would be considered quality-assured after successful completion of all required accuracy testing, visual inspections and diagnostic tests, the baseline would have to be re-established no later than the end of the second flowmeter operating quarter following the quarter in which the quality assurance tests are completed.

Rationale:

EPA is proposing to incorporate by reference the standard: American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the *Manual of Petroleum Measurement Standards,* October 1988 edition. The Agency has already approved this method of fuel flowmeter testing in response to a petition (see Docket A–97–35, Item II-C–6). This is also a standard agreed to by API that is traceable to NIST standards. The Agency has a general policy of approving standards from technically knowledgeable groups such as the Organization for International Standards (ISO), the American Society for Testing and Materials (ASTM), the American Society of Mechanical Engineers (ASME), the American Gas Association (AGA), the Gas Processors Association (GPA), and API. EPA would also be willing to incorporate additional standards by reference if commenters supply a copy for consideration.

The Agency recognizes that it is difficult and sometimes costly to take a fuel flowmeter out from its installation location to be tested (see Docket A–97–35, Item II-E–22). Today's proposed rule would provide the flexibility of an additional approach for testing fuel flowmeters where they are installed. Today's proposal for a fuel flow rate-to-load comparison test would allow facilities to assure the quality of their fuel flow rate data without taking a fuel flowmeter out of line. Several industry representatives suggested that a fuel flow rate-to-load comparison was a useful approach to quality assuring data (see Docket A–97–35, Items II–E–22, II–E–23). Some industry representatives felt that a fuel flow rate-to-load ratio was straightforward and even more representative than a stack flow rate-to-load ratio (see Docket A–97–35, Item II-E–23).

In general, utilities have indicated that the idea of a fuel flow-to-load ratio is an appropriate quality assurance test for fuel flowmeters (see Docket A–97–35, Items II–D–30, II–D–41, II–E–33). Use of the fuel flow-to-load ratio was first suggested to the Agency as an alternative to annual orifice inspections (see Docket A–97–35, Item II–E–22). One utility mentioned that the fuel flow-to-load ratio test would be most useful if it allowed them to stretch the time between transmitter or transducer accuracy tests on orifice-, nozzle-, and venturi-type fuel flowmeters, as well as primary element inspections and fuel flowmeter accuracy tests performed in-line against a ''master meter'' or performed in a laboratory (see Docket A–97–35, Item II–D–49).

Utilities have also indicated that they would prefer the provisions of the fuel flow-to-load ratio test to be as similar as possible to the stack flow-to-load ratio test in today's proposed rule (see Docket A–97–35, Item II-E–33). This would be easier for facilities to comply with because they would need to learn fewer new procedures, they could use the same equations and algorithms in computer software or hand calculations, and they could report information in a similar format. To the extent possible, the Agency has incorporated this suggestion in today's proposed rule. However, because monitoring with fuel flowmeters is not identical to monitoring with stack volumetric flow monitors, there are some differences in the procedures and in the data to be recorded and reported.

Today's proposed rule would allow the quarterly fuel flow-to-load ratio test as an optional supplement to flowmeter accuracy tests under section 2.1.5.1 or 2.1.5.2 of Appendix D, transmitter or transducer accuracy tests under section 2.1.6.1 of Appendix D for orifice-, nozzle-, and venturi-type fuel flowmeters, and visual inspections of the primary element required under section 2.1.6.6 of Appendix D for orifice-, nozzle-and venturi-type fuel flowmeters. These more rigorous fuel flowmeter quality assurance procedures would still be required at least once every 20 calendar quarters (five years), even if the procedures of section 2.1.7 of Appendix D were followed. The Agency has proposed a quarterly fuel flow-to-load ratio test for several reasons: (1) this is consistent with the provisions of the proposed volumetric stack flow-to-load ratio test in today's proposed rule; (2) the test involves examining data more closely when preparing quarterly reports; and (3) a quarterly test allows facilities to find problems in fuel flowmeter data before an entire year has passed. The Agency also considered requiring the fuel flow-to-load ratio to be used more frequently than quarterly, perhaps daily; however, this would require facilities to spend far more time and effort in evaluating data at different times during the quarter than they may do currently, particularly for small, infrequently operated units. In addition, many utilities claim that fuel

flowmeters tend to be stable, and therefore little change would be expected over short time periods such as a day (see Docket A–97–35, Item II–E–33).

EPA is proposing that the optional fuel flow-to-load ratio test could serve as a supplement to other quality assurance procedures for fuel flowmeters for up to 20 calendar quarters (five years). EPA is proposing a time period of 20 calendar quarters for the following reasons. First, it is similar to the current provision in section 2.1.5.2 of Appendix D, which allows a reference fuel flowmeter to be accuracy tested as seldom as once in five calendar years if comparison with an in-line ''master'' flowmeter shows less than a 1.0 percent difference in their flow rates. Second, a five-year test cycle offers certain administrative advantages. For instance, fuel flowmeters used to provide heat input data for the heat input-versus-load correlation of Appendix E could be accuracy-tested before each Appendix E test (i.e., once every five years). In addition, a five-year period would ensure that fuel flowmeters are tested by the time the unit's operating permit is renewed. The 20 calendar quarter (five-year) period is consistent with the provisions for reduced three-level flow RATAs for stack flow monitors. The 20 calendar quarter (five-year) period between tests is also consistent with the proposed time between quality assurance tests for fuel flowmeters that are used very infrequently. Repeating the periodic quality assurance procedures for fuel flowmeters at least every five years would catch slow, long-term changes in heat rates mentioned by a facility and would allow a facility to update its baseline data periodically (see Docket A–97–35, Item II–D–49). Finally, allowing the option of a 20 calendar quarter (five-year) period between more rigorous quality assurance procedures would be safer and less costly than annual testing, while, in coordination with quarterly fuel flow-to-load ratio testing, still providing assurance of the quality of the data.

(1) *Use of Gross Heat Rate or Flow-to-Load Ratio.* Today's proposed rule would allow a facility the option of calculating either the ratio of the fuel flow rate to the gross generation in MWe or the steam flow rate in thousands of pounds of steam per hour (''fuel flow-to-load ratio'') or the ratio of the heat input rate to the gross generation in MWe or the steam flow rate in thousands of pounds of steam per hour (''gross heat rate'' or ''GHR''). One utility suggested that, because the load is created based upon a number of factors in addition to the fuel flow rate, such as the gas heat rate (i.e., gross calorific value), a ratio of the heat input to the unit load would be a better test than the ratio of the fuel flow rate to the unit load (see Docket A–97–35, Item II–D–50). In addition, some utilities pointed out that the Agency allows facilities to use either a stack flow-to-load ratio or a heat input-to-load ratio (gross heat rate) as a diagnostic test on stack volumetric flow monitors, through Policy Manual Question 13.15 (see Docket A–97–35, Item II–I–9). The Agency agrees that the heat input-to-load ratio (GHR) is also a technically appropriate check on the performance of fuel flowmeters. Therefore, today's proposal includes options for both the fuel flow-to-load ratio and the GHR.

(2) *Baseline Period for Fuel Flow-to-Load Ratio or GHR.* When using this type of comparison test, it is important to establish a baseline of reliable data to which hourly data can later be compared. For the stack volumetric flow-to-load ratio, the baseline of reliable data consists of data from the reference method for flow, Method 2 of Appendix A to 40 CFR part 60. However, there is no universally applicable test for flowmeters that is performed in-line with a reference method while the unit is operating, parallel to the flow RATA. EPA asked several utilities what could be a source of baseline data to which the fuel flowmeter could later be compared. One utility suggested using fuel flowmeter readings during a time when the unit is operating at a steady load, such as when the unit undergoes Appendix E testing for a NO_X-versus-heat input correlation or when a NO_X CEMS undergoes a normal level RATA (see Docket A–97–35, Item II–D–41). A second utility recommended that the baseline be established just after performing a transmitter calibration, i.e., after performing a quality assurance test on the fuel flowmeter (see Docket A–97–35, Item II–D–49). The Agency believes that using fuel flowmeter data taken immediately following a flowmeter quality assurance test would be most likely to be accurate and representative of proper operation of the fuel flowmeter. Flowmeter quality assurance tests might include any of the methods incorporated by reference in section 2.1.5.1 of Appendix D; meter testing against a certifiable ''master'' meter under section 2.1.5.2 of Appendix D; or transmitter or transducer accuracy testing under section 2.1.6.1 of Appendix D, and inspection of a primary element for an orifice-, nozzle-, or venturi-type fuel flowmeter under section 2.1.6.6 of Appendix D. This approach is proposed in today's rule.

The utilities supporting the idea of using fuel flowmeter data taken immediately after a flowmeter quality assurance test have suggested that it would be important to have a fairly large number of hours in the baseline, on the order of 100 or more, to ensure that the baseline period is representative of typical operation (see Docket A–97–35, Item II–E–33). In today's rule, EPA is proposing to use the first 168 hours of quality assured data measured by that flowmeter for which: (1) only the fuel measured by that fuel flowmeter is combusted; (2) the unit load is not significantly ''ramping'' up or down; and (3) the unit load is safely above the minimum safe, stable load. The Agency believes that a baseline period containing 168 hours of data is sufficiently long to be representative of different unit operating conditions that may occur later. This specific time period is consistent with the minimum number of hours that a unit combusts a fuel before the quarter counts toward the deadline for the next quality assurance test, and with the minimum number of hours that a unit combusts a fuel before a quarter needs to be evaluated using the fuel flow-to-load ratio. Certain hours would be excluded from the baseline (i.e., periods of co-firing, unstable, or low load), because the fuel flow-to-load ratio or GHR would tend to be less reliable during those periods.

Today's proposal would also limit the baseline period so that it may extend no more than two quarters beyond the quarter in which the flowmeter passes its accuracy tests. The Agency has concerns that if the baseline data were to extend longer than this, the performance of the fuel flowmeter might degrade. In order for the baseline data to reflect fuel flow rate data that are most likely to be accurate, the Agency is proposing that the fuel flow rate or heat input rate data used in the baseline period must either be obtained in the calendar quarter in which the quality assurance procedure is performed, or within two calendar quarters after the QA test. The Agency considered limiting the time period to the same calendar quarter as the quality assurance procedure or to one flowmeter operating quarter beyond the QA test. However, because a quality assurance procedure may be conducted at any time during a quarter, it could be difficult for a facility to collect 168 hours of fuel flowmeter data after a quality assurance procedure in the same calendar quarter or even (for infrequently operated units that ramp

up and down often) in the next calendar quarter.

For orifice-, nozzle-, and venturi-type fuel flowmeters, two quality assurance procedures would be required prior to collecting the baseline data: (1) a transmitter or transducer accuracy test, and (2) an inspection of a primary element. The Agency considered whether these two quality assurance procedures should be separated and whether the baseline period could simply be based upon a time period after the most recent quality assurance procedure. The Agency believes that the baseline period data would be more reliable if they were taken shortly after completing both quality assurance procedures for orifice-, nozzle-, and venturi-type fuel flowmeters. Using the same time period for both tests simplifies administration of the fuel flow-to-load ratio test. EPA also notes that a unit does not need to be operating in order to perform the tests; thus, it should not be burdensome for a facility to plan to coordinate the two quality assurance procedures.

(3) *Data Preparation and Analysis.* The proposed procedures for data preparation and analysis for the fuel flow-to-load ratio are similar to those for the volumetric stack flow-to-load ratio. Equations of the same form as those for the stack volumetric flow-to-load ratio are used to calculate the hourly fuel flow-to-load ratio, the hourly absolute value of the percentage difference between the baseline fuel flow-to-load ratio and the hourly fuel flow-to-load ratio, and the quarterly average percentage difference. Common pipe headers would be treated in the same way as common stacks. If there were multiple units associated with a single fuel flowmeter or flow monitor, the total load from all units would be summed before the flow rate data are divided by the load data to calculate the flow-to-load ratio. Fuel flowmeters on multiple pipes would be treated in the same way as multiple stacks associated with a single unit. If there are multiple fuel flowmeters or flow monitors associated with a single unit, the flow rates from all fuel flowmeters for the same fuel or all flow monitors would be added together before the flow rate data are divided by the load data to calculate the flow-to-load ratio.

Certain aspects of the volumetric stack flow-to-load ratio test are not the same for the fuel flow-to-load ratio test. For example, the volumetric stack flow-to-load ratio test requires the facility to screen out those hours when the unit operates further than 10.0 percent away from the average load during the most recent normal-load flow RATA. As was discussed previously, there is no equivalent of an in-line flow RATA for fuel flowmeters. EPA does not believe that there is a need to screen out hours for the fuel flow-to-load test when the unit operates at a load somewhat less than or greater than normal. Some facilities have indicated that the fuel flow-to-load ratio or GHR based on fuel flow readings is less variable over different loads than the volumetric stack flow-to-load ratio (see Docket A–97–35, Items II–E–33 and II–D–98). However, preliminary evidence has also indicated that the fuel flow-to-load ratio or GHR can be significantly different at very low operating loads than at other load levels (see Docket A–97–35, Item II–A–5). For this reason, EPA is proposing to allow hours in which the unit load is within the lower 10.0 percent of the range of operation to be excluded from both the baseline data and the quarterly flow-to-load or GHR analysis, unless such low loads are considered normal for the unit.

Another feature of the volumetric stack flow-to-load ratio test that differs from the fuel flow-to-load ratio test is the treatment of bias-adjusted data. Fuel flow rate data are never adjusted for bias. There is no bias test for fuel flowmeters. Bias-adjustment of data is an issue for the volumetric stack flow-to-load ratio test because bias-adjusted data has already been adjusted to make it more consistent with the value of the reference method data. Thus, bias-adjusted volumetric stack flow data must meet a stricter quarterly average percentage difference of 10.0 percent from the reference flow-to-load ratio, whereas the allowable difference is 15.0 percent when unadjusted volumetric stack flow data are used. (See discussion of stack flow-to-load test in Section III.M. of this preamble.) EPA notes that since the same fuel flow meter is used to produce both the baseline data and the quarterly data, the fuel flow-to-load ratio is more closely analogous to the use of bias-adjusted volumetric flow data. Therefore, the limit on the quarterly average percentage difference from baseline for fuel flow rate data should be at least as stringent as that for bias-adjusted volumetric flow data (10.0 percent). Information provided by facilities on the gross heat rate derived from fuel flow rate data have shown less variability than the corresponding stack heat rate (see Docket A–97–35, Item II–D–98). Based upon this information, EPA is proposing a limit of 10.0 percent on E_f, the quarterly average percentage difference from the baseline for the quarterly flow rate-to-load or GHR evaluation. EPA considered whether it would be appropriate to set a different limit for smaller units, as was done for the stack flow-to-load test. Analysis of some preliminary fuel flow-to-load data has shown that for lower loads (e.g., < 50 MWe), the flow-to-load ratio is quite sensitive to small changes in load (see Docket A–97–35, Item II–A–5). This indicates that it would be appropriate to set a higher limit for smaller units. Therefore, today's rule proposes a limit of 15.0 percent on the value of E_f when the quarterly average load used for the data analysis is 50 megawatts or less (or ≤ 500 klb steam per hour). The Agency solicits comment on the 15.0 percent limit for loads less than or equal to 50 megawatts.

(4) *Optional Data Exclusions.* As for volumetric stack flow monitors, if a fuel flowmeter's data would not meet the limit on the percentage deviation from the baseline, then a facility could opt to exclude certain hours of unrepresentative fuel flow rate (or heat input rate) data and then reanalyze the smaller set of data. The hours of data that EPA proposes to view as non-representative for fuel flowmeters are: (1) hours when the unit combusts multiple fuels; (2) hours when the unit load in a given hour would differ by more than ± 15.0 percent from the load during either the previous hour or the subsequent hour; or (3) hours when the load is very close to the minimum safe, stable load (unless operation in that range is normal).

The baseline period for fuel flowmeters and the data used for the quarterly flow-to-load or GHR analyses would include only those hours when a single fuel is combusted—the fuel measured by the fuel flowmeter. If the quarterly fuel flow rate data included hours when multiple fuels are co-fired, the fuel flow-to-load ratio or GHR for the fuel flowmeter being tested would be biased low. This could result in a failure of the flow-to-load test or GHR evaluation. Today's proposed rule would also allow a facility to exclude from the baseline data and the quarterly analyses those hours that are not representative because the unit's load is changing rapidly. Specifically, hours could be excluded when the unit load in a given hour would differ by more than ± 15.0 percent from the load during either the previous hour or the hour afterwards. There will be a lag in the time between when electricity is generated and registered as load and the time that the fuel flowmeter measures the fuel that is combusted to generate the load. Therefore, during an hour when the load changes rapidly, the fuel flow rate will not necessarily be changing by the same amount or in the

same direction. At least one utility has suggested that the Agency consider such an exclusion for the proposed fuel flow-to-load ratio test (see Docket A–97–35, Item II–D–41).

In general, the fuel flow is directly proportional to load, with a linear graphical relationship. However, this is not always the case at extremely low loads (see Docket A–97–35, Items II–E–33, II–D–98). Therefore, today's proposed rule would allow certain low-load hours to be excluded from the flow-to-load baseline and quarterly data analyses. Specifically, loads in the lower 10.0 percent of the ''range of operation'' of the unit, (as that term is defined in proposed section 6.5.2.1 of Appendix A in today's proposal) could be excluded, unless such loads are considered normal for the unit.

Today's proposed rule, in section 2.1.7 of Appendix D, would also exempt a fuel flowmeter from the fuel flow-to-load ratio test in a quarter when a more rigorous quality assurance test is performed. This is unlike the volumetric stack flow-to-load ratio, which is required each QA operating quarter, including quarters when the flow monitor is tested with a RATA (provided, of course, that sufficient data for the analysis are obtained after the RATA).

(5) *Consequences of Failing the Fuel Flow-to-Load Ratio Test.* The consequences of failing the fuel flow-to-load ratio test would be similar to the consequences of failing quality assurance tests in general for fuel flowmeters. Data from the fuel flowmeter would no longer be considered quality assured. Because the fuel flow-to-load ratio test is only performed at the end of a quarter, the facility would invalidate data from the fuel flowmeter beginning with the first hour in the quarter after the quarter in which the meter fails the fuel flow-to-load ratio test. In order to establish that the fuel flowmeter is operating properly and providing quality assured data again, the facility would perform a flowmeter accuracy test or (for orifice-, nozzle-, and venturi-type flowmeters) a transmitter or transducer accuracy test. The Agency believes it is appropriate to perform an accuracy test if the fuel flow-to-load ratio test is failed, because in such cases the facility has had the benefit of postponing the accuracy test based upon the assumption that the fuel flowmeter has continued to measure accurately and consistently with its operation during the baseline period.

Note that for orifice-, nozzle-, and venturi-type fuel flowmeters, a transmitter/transducer test alone would not suffice to demonstrate that the flowmeter is back in control. The owner or operator would still need to ensure that the cause of the failed fuel flow-to-load ratio test was a problem with the transmitters or transducers rather than a problem with the primary element. Sudden changes in flowmeter performance are likely to be caused by a problem with transmitters (see Docket A–97–35, Item II–D–33). However, it cannot be assumed that the transmitters are solely responsible for degradation in monitor performance. In order to verify that the primary element is not contributing additional error to the fuel flow measurements because of corrosion, a facility would conduct an abbreviated (6 to 12 hour) version of the fuel flow-to-load ratio test, similar to the diagnostic test for volumetric stack flow monitors in Policy Manual Question 13.15 (see Docket A–97–35, Item II–I–9). The Agency believes that this abbreviated fuel flow-to-load ratio test would provide additional assurance that the fuel flowmeter is indeed operating properly. In addition, it would be more timely than waiting for another calendar quarter to pass to repeat the fuel flow-to-load ratio. The abbreviated test would also be less burdensome than removing the primary element from the fuel pipe. EPA believes the abbreviated fuel flow-to-load ratio test strikes a reasonable balance by providing some additional quality assurance in a timely manner. If the orifice-, nozzle-, or venturi-type fuel flowmeter failed the abbreviated fuel flow-to-load ratio test, then it would appear that the primary element may also have a problem. Therefore, upon failure of an abbreviated fuel flow-to-load ratio test, the facility would be required to inspect the primary element and to repair or replace it, as necessary.

The rules for data validation upon failure of the fuel flow-to-load ratio are not parallel with the procedures for data validation following failure of the volumetric stack flow-to-load ratio test in that there is no conditional validation of data. A number of utilities have emphasized that they wish to spend less time and effort preparing and evaluating quarterly reports for units using Appendix D, which are generally smaller and less frequently operated than coal-fired units or oil-fired units that choose to use CEMS (see Docket A–97–35, Item II–E–33). The concept of conditional data validation for fuel flowmeters is not consistent with this objective, because it would introduce additional complexity into the process, would require significantly more time and resources to quality-assure the data, and might require additional DAHS programming. Therefore, the Agency is not proposing the use of conditional data validation for fuel flowmeters.

(c) Fuel Flowmeter Quality Assurance Testing Frequency

Background

Section 2.1.6.1 of Appendix D, as revised by the May 17, 1995 direct final rule, requires regular quality assurance ''recalibrations'' (accuracy tests) of fuel flowmeters at least annually (once every four calendar quarters). For fuel flowmeters that were not used on a regular basis, such as fuel flowmeters used to measure the usage of emergency fuel or backup fuel, or flowmeters installed on peaking units, owners or operators are allowed to do flowmeter accuracy tests once every four quarters when the unit actually combusts the fuel measured by the flowmeter, rather than once every four calendar quarters. Flowmeters can be retested either by using one of the methods incorporated by reference in section 2.1.5.1 of Appendix D to part 75 or by an in-line comparison of the fuel flowmeter against a ''master'' fuel flowmeter using the procedure in section 2.1.5.2 of Appendix D.

Some utilities have expressed concern about the annual fuel flowmeter testing requirement (see Docket A–97–35, Items II–D–20, II–E–13, II–E–14). In many cases, it is neither practical nor cost-effective to modify the fuel pipes (e.g., to install a parallel length of pipe) to allow installation of a master fuel flowmeter for comparison testing. Thus, most utilities must remove a fuel flowmeter from the pipe and return it to a laboratory or to the manufacturer to be retested. In some cases, especially for oil flowmeters, this can be difficult.

Some utilities have raised the issue of whether there should be a minimum time period that a fuel flowmeter is used before a quality assurance test is required. For instance, a utility might test its unit's burners once each quarter for a few hours to ensure that the unit can be operated when needed and may not operate for the rest of the quarter. Under the current rule, the fuel flowmeter would have to be quality assurance tested after four such operating quarters, even though the flowmeter was only used for a few hours in those calendar quarters.

Discussion of Proposed Changes

Today's proposed rule includes a provision that only those calendar quarters in which the fuel measured by the fuel flowmeter is combusted for at least 168 hours would count toward determining the next quality assurance test deadline. The 168-hour time period

is roughly equivalent to one week of operation while combusting the fuel measured by a particular fuel flowmeter. A calendar quarter in which the fuel measured by a fuel flowmeter is combusted for 168 hours or more would be called a ''flowmeter operating quarter.'' For example, if a unit combusted oil for 200 hours in the first calendar quarter of the year, 10 hours in the second calendar quarter, 250 hours in the third calendar quarter, and 100 hours in the fourth calendar quarter, then only the first and third calendar quarters would be considered flowmeter operating quarters for the oil flowmeter. Only the first and third calendar quarters would count toward determining the deadline for the next required oil flowmeter accuracy test.

In today's proposed rule, each fuel flowmeter would need to be accuracy tested at least once every four flowmeter operating quarters. However, the deadline for testing infrequently-used meters could not be extended indefinitely. No more than 20 calendar quarters (five years) would be allowed to elapse between successive flowmeter accuracy tests, regardless of the number of ''flowmeter operating quarters'' that have elapsed since the last test. The interval between successive quality assurance tests could also be extended for up to 20 calendar quarters if the quarterly fuel flow rate-to-load procedures in proposed section 2.1.7 of Appendix D were implemented.

Rationale

In evaluating the frequency of fuel flowmeter accuracy testing, EPA considered simply extending the less strict requirement for fuel flowmeter quality assurance testing for peaking units, backup fuel, and emergency fuel to apply to all units and all fuel flowmeters. Thus, quality assurance testing would be required once every four quarters in which the unit combusted the fuel measured by the flowmeter.

One industry representative recommended that the Agency require fuel flowmeter calibrations once every four unit operating quarters, where a unit operates at least 168 hours in the quarter (see Docket A–97–35, Item II–E–13). This approach would treat all fuel flowmeters the same, whether they were used for primary, emergency, or backup fuel.

Another utility suggested that the Agency consider creating some sort of diagnostic test comparing the flow rate of the fuel flowmeter to the unit load (generation) to determine whether the fuel flowmeter readings are degrading over time, rather than specifying a particular frequency for accuracy testing (see Docket A–97–35, Item II–E–22). Although this suggestion was originally referring to problems with corrosion of an orifice plate, such a test could also be used for other types of fuel flowmeters as a check on the quality of fuel flowmeter data.

The Agency also considered extending the typical time between accuracy tests to the equivalent of two years. This time was suggested by a member of the AGA subcommittee responsible for the drafting of AGA Report No. 7 for turbine-type flowmeters (see Docket A–97–35, Item II–E–17). The Agency also considered extending the typical time between accuracy testing to 12 calendar quarters—the equivalent of three years. Three years is the period of time that records must be retained in a file at the source under § 75.54 (or proposed § 75.57).

The Agency also considered allowing fuel flowmeters to continue for up to five calendar years between accuracy tests. This is similar to the current provision in section 2.1.5.2 of Appendix D, which allows a reference fuel flowmeter to be accuracy tested as seldom as once in five calendar years, if the in-line comparison with a master fuel flowmeter shows a 1.0 percent or less difference in their flow rates. A five-year test cycle offers certain administrative advantages. For instance, fuel flowmeters used to provide heat input data for the heat input-versus-load correlation of Appendix E could be accuracy-tested before each Appendix E test (i.e., once every five years). In addition, the five calendar-year period would ensure that fuel flowmeters are tested by the time the unit's operating permit is renewed. Facilities might find this time cycle easier to determine than a time period based upon a number of calendar quarters. However, test data would need to be retained for five years, rather than for three years, the recordkeeping period for most records under part 75. However, the Agency is not proposing this option because five years is far too long a period of time to allow a unit to continue with no checks at all upon the quality of its data. Such an approach would allow the use of data from a fuel flowmeter that potentially had been reading inaccurately for the previous five years.

Another option that EPA evaluated was to establish different fuel flowmeter quality-assurance testing frequencies depending on the fuel measured by the fuel flowmeter. Under this approach, oil flowmeters would need to be tested every four calendar quarters in which oil was combusted. Gas flowmeters would only need to be tested once every five years. The two fuels would be treated differently because units emit less NO_X and far less SO_2 when combusting gas than when combusting oil. In addition, gaseous fuels, particularly pipeline natural gas, should be less corrosive; therefore, a gas flowmeter should be less likely to degrade than an oil flowmeter.

EPA believes that today's proposed approach to reducing the fuel flowmeter quality assurance testing frequency takes into account many of the concerns raised by utilities. All unit types and fuel types would have the same frequency of testing. This would avoid confusion that could follow from an approach that set different requirements for fuels or units that are used less frequently. A group of utilities had indicated that they prefer a more consistent approach (see Docket A–97–35, Item II–E–13). Under today's proposal, infrequently-used fuel flowmeters (e.g., meters for backup fuel or emergency fuel) would only need to be calibrated once every five years. When a facility renews its operating permit, the permitting agency could verify that all fuel flowmeters have been tested at least once in the previous five years.

The minimum period of 168 hours of fuel flowmeter usage which defines a ''flowmeter operating quarter'' is consistent with the definition of a ''QA operating quarter'' in Appendix B in today's proposed rule for the quality assurance of CEMS. The Agency believes that using a consistent minimum number of hours in a calendar quarter for both CEMS and fuel flowmeters will make implementation easier for facilities and air regulatory agencies. In addition, 168 hours should be a sufficiently long period of time to ensure that short-term usage of backup fuel or emergency fuel or short-term tests of a unit do not trigger unnecessary quality assurance testing.

Today's proposed rule would also provide more flexibility in the methods that could be used for fuel flowmeter quality assurance testing. As discussed above in Section III.P.2 of this preamble, a new testing procedure has been proposed that would allow a facility to test flow rate-to-load ratio of the fuel flowmeter while leaving it installed. Thus, the Agency believes that the overall burden of fuel flowmeter testing has been significantly reduced. In addition to the reduced frequency of testing discussed above, the Agency believes the less burdensome testing procedures should address concerns of the regulated community.

The Agency requests comment on whether facilities would prefer to base

the frequency of fuel flowmeter quality assurance testing on the type of fuel used or the amount of time the fuel flowmeter is used. Under the first approach, gas flowmeters would receive greater regulatory relief. Under the second approach, which is being proposed in today's rule, infrequently-used flowmeters (typically oil flowmeters) would receive greater regulatory relief.

(d) Orifice, Nozzle, and Venturi Visual Inspections

Background

Section 2.1.6 of Appendix D, as revised in the May 17, 1995 direct final rule, created special provisions for the ongoing quality assurance testing of orifice fuel flowmeters. Orifice-, nozzle-, and venturi-type fuel flowmeters are designed and installed within a set of physical specifications, such as the orifice diameter (see Docket A–97–35, Item II–D–13). Maintaining these physical specifications determines the flowmeter's ability to read accurately. Thus, it is not necessary to take an orifice-, nozzle-, or venturi-type flowmeter out of line and send it to a laboratory to determine its accuracy.

After installation of an orifice-, nozzle-, or venturi-type flowmeter is complete, the two major factors that contribute to error in flow readings are: drift in the transmitters (or transducers) which determines the total pressure, differential pressure and temperature, and corrosion of the primary element (e.g., the orifice plate) itself. Quality assurance testing of the transmitters is discussed in the next section of the preamble. In order to identify cases where error might result from corrosion of the orifice plate, the May 17, 1995 direct final rule added a requirement for an annual visual inspection of the orifice plate. If an orifice plate fails the inspection, then the facility must perform a test on the transmitters during the next calendar quarter. A procedure for visual inspections is given in Appendix B of part 2 of American Gas Association (AGA) Report No. 3, which is one of the accepted standards for installation and use of orifice flowmeters.

Some facilities have expressed concern with the frequency of visual inspections (see Docket A–97–35, Items II–D–20, II–E–13, II–E–14). This process must be done either with a tool, such as a boroscope, or else the primary element must be removed from the pipe and lifted out to be inspected. In the case of large, heavy orifices, it is necessary to use a crane to remove the orifice. Fuel must not be flowing through the pipe while the orifice plate is being removed (see Docket A–97–35, Item II–E–8).

The current provisions of Appendix D to part 75 do not explicitly state the consequences of failing a quality assurance test. Section 2.1.5.1 of Appendix D states that if a fuel flowmeter exceeds the flowmeter accuracy of ± 2.0 percent of the upper range value, then the flowmeter may not be used under part 75. Section 2.1.5.2 states that if a fuel flowmeter's accuracy exceeds ± 2.0 percent of the upper range value, then the flowmeter must be recalibrated to meet that accuracy, or it must be replaced with another flowmeter that meets the specification. Neither section explicitly states the impact upon the validity of data if a test is failed. However, if fuel flowmeter systems are to be treated parallel with continuous emission monitoring systems under § 75.21(e)(2), the consequences of failing a quality assurance test for a fuel flowmeter or an inspection of the primary element should result in the monitor being considered out-of-control and the data being considered invalid.

In section 2.1.6.1 of Appendix D, the specific consequence of failing a visual inspection of the primary element is that the transmitters must be tested in the following calendar quarter, rather than waiting until the regular annual calibration is required. However, no mention is made of any mandatory corrective action(s) to eliminate the corrosion problem.

Discussion of Proposed Changes

Section 2.1.6.6 of Appendix D in today's rulemaking proposes to require visual inspections of primary elements (i.e., orifice, nozzle or venturi) at the frequency recommended by the manufacturer or once every three years, whichever is more frequent. The Agency solicits comment on the proposed frequency of visual inspections.

The proposed rule would also explicitly require repair or replacement of the primary element and invalidation of data when a visual inspection is failed. Once the primary element is replaced or repaired, the new or repaired primary element would have to demonstrate that it meets the overall flow rate accuracy of ± 2.0 percent of the upper range value. This could be demonstrated by showing that the new or repaired primary element meets the design and installation requirements of AGA Report No. 3 or ASME MFC–3M, the same methods required for initial certification. Alternatively, the flow rate accuracy could be demonstrated by testing the fuel flowmeter against a reference fuel flowmeter using the provisions of section 2.1.5.2 of Appendix D. Finally, whenever a primary element is repaired, the fuel flowmeter transmitters would also have to be tested before the fuel flowmeter is used to provide quality assured data.

Rationale

During the process of reviewing certification applications for units using orifice flowmeters, the Agency learned of one plant where orifice corrosion was a serious problem. This utility had an orifice flowmeter which had been installed in the 1960's. This utility did not have documentation of the standard used to install the orifice as a demonstration of the meter's accuracy. In order to qualify for certification, the utility inspected the orifice. The utility personnel discovered that the orifice had been completely eaten away and was incapable of reading the flow rate (see Docket A–97–35, Item II–E–22). The utility replaced the orifice before it was able to have its fuel flowmeter certified. In addition, it was required to invalidate the flow rate data from the orifice meter and substitute for the missing data. Based upon this experience, the Agency believes that corrosion of an orifice can be a problem, and that in severe cases of corrosion, replacement of the orifice is necessary.

Despite this, many utilities have expressed concern over the difficulty of removing an orifice from place for visual inspection (see Docket A–97–35, Items II–D–20, II–E–13, II–E–14), because removal requires halting the flow of gas through the pipeline in order to remove the orifice, which can be expensive (see Docket A–97–35, Item II–E–8).

Utilities have provided the Agency with several suggestions for reducing the frequency of primary element inspections. One industry group recommended that the Agency reduce the inspection frequency to once every five years, to be coordinated with renewal of the plant's operating permit under title V of the Act (see Docket A–97–35, Items II–D–20, II–E–13, and II–E–14). One utility representative mentioned that most orifice manufacturers recommend an inspection once every three years; thus, he recommended that the Agency require visual inspections the earlier of once every three years or the time period specified by the manufacturer (see Docket A–97–35, Item II–D–41). Another utility suggested that the Agency consider creating some sort of diagnostic test comparing the flow rate of the fuel flowmeter to unit load (generation) to determine whether the fuel flowmeter readings are degrading

over time, rather than specifying a particular time period (see Docket A–97–35, Item II–E–22).

EPA agrees that it would be helpful to facilities to reduce the frequency of visual inspections from their current annual frequency. Having considered all of the options suggested by the utilities, the Agency is proposing that the primary element of all nozzle, venturi and orifice fuel flowmeters be visually inspected at the frequency recommended by the manufacturer or once every three years, whichever is the more frequent. The Agency believes that up to three years between visual inspections is a technically sound period of time that will assure the quality of fuel flow rate data, while providing regulatory relief from the current annual requirement.

The Agency also has reconsidered the consequences of failure of a visual inspection. The May 17, 1995 direct final rule added a requirement to test a flowmeter's transmitters in the calendar quarter following a failed inspection, but the rule does not explicitly require that the primary element be repaired or replaced, nor does it explicitly require data from the fuel flowmeter to be invalidated.

Today's proposed rule would require the primary element to be removed following a failed visual inspection and would require the problem to be corrected. The Agency believes that it is appropriate to provide two options for correcting the problem: either replace the element with a new one or repair it. This would provide flexibility to facilities, while still assuring that the fuel flowmeter will be repaired to give quality assured data.

Today's proposed rule would also change the timing of the requirement for fuel flowmeter transmitter or transducer testing if a primary element fails its visual inspection. The Agency believes that it would be appropriate also to test the fuel flowmeter transmitters before the fuel flowmeter is placed into service again. This would be a more thorough quality assurance check of the entire fuel flowmeter than simply addressing the problem with the primary element. Thus, when the fuel flowmeter is placed into service again, its accuracy would be tested as fully as possible. In addition, EPA proposes to remove the requirement for a test on the flowmeter transmitters in the calendar quarter following a failed visual inspection. This requirement might be appropriate if it seemed that transmitter drift was likely to be a problem or if the Agency had no other means of assuring the quality of the data from the flowmeter after a problem with the primary element was known to have occurred. However, the Agency believes that problems with the primary element are separate from problems with drift in the transmitters. Because today's proposal would require a check on the fuel flowmeter transmitters after repair or replacement of the primary element, requiring an additional test of the transmitters in the following calendar quarter appears to be unnecessary.

The proposed rule gives procedures for data validation when a primary element fails a visual inspection. The element would have to be replaced or repaired, and the transmitters would have to be tested before data would again be valid from the fuel flowmeter. During the period in which the flowmeter data are considered invalid, the appropriate missing data substitution procedures would be used. The Agency has clarified that these data validation procedures would also apply to failures of other fuel flowmeter quality assurance tests. EPA believes that this will make facilities' obligations clearer. In addition, the Agency believes that fuel flowmeter systems should be treated as consistently as possible with CEMS. Consistent treatment simplifies the part 75 requirements and is more equitable for sources using different monitoring approaches.

(e) Orifice, Venturi, and Nozzle Flowmeter Transmitter Testing

Background

As discussed previously, once an orifice-, nozzle-, or venturi-type flowmeter has been installed, one of the major causes of error in the measured flow rates is drift in the transmitters or transducers that determines the total pressure, differential pressure, and temperature. The flow measurement error for these types of flowmeters is a combination of the errors in these individual transmitters or transducers and a constant error value associated with the physical dimensions of the primary element. The May 17, 1995 direct final rule added a requirement that flowmeter transmitters be tested at least annually. The transmitters are also required to be retested in the next calendar quarter if the overall flow rate error is greater than 1.0 percent of the upper range value of the flowmeter. For practical purposes, this requires a facility to know the error from the physical dimensions of the primary element in order to determine if the flowmeter meets the overall accuracy requirement.

Some utilities asked the Agency how to determine the overall flowmeter accuracy from individual transmitter values (see Docket A–97–35, Item II–E–31). EPA addressed this issue in Policy Guidance (see Docket A–97–35, Item II–I–9, Policy Manual, Question 10.17). This guidance included a formula for calculating total flowmeter accuracy from error in transmitter readings for differential pressure, static pressure and temperature, and error from all other sources (i.e. physical dimensions of the primary element). Some utilities indicated that they do not always have information available on the constant error from other portions of the primary element (see Docket A–97–35, Item II–E–13). The policy guidance also indicated that a facility could report test results electronically using the highest amount of error from any of the three transmitters. Provided that the highest error from an individual transmitter is 1.0 percent of the upper range value of the transmitter or less, the overall flowmeter accuracy will be less than 2.0 percent of the upper range value (see Docket A–97–35, Item II–I–10).

EPA has also observed that transmitter test data reported for orifice-, nozzle-, and venturi-type flowmeters have not been consistent. Some facilities test each transmitter once at three different levels, including a low, middle, and high value (see Docket A–97–35, Item II–D–16). Others test each transmitter at five different levels, including zero, full scale, and three intermediate levels (see Docket A–97–35, Item II–D–17). The Agency had previously issued some guidance on reporting test results, both for orifice flowmeters and other flowmeters (see Docket A–97–35, Items II–I–4, p. 3–58, and II–I–9, Policy Manual, Questions 10.17 and 12.27). However, this guidance appears to have been insufficient, as utilities have continued to request guidance in how to perform and report test results (see Docket A–97–35, Item II–D–21). Questions have included the number of levels at which transmitters should be tested, whether all of these levels must be non-zero, the number of times the transmitter should be tested at a particular level, if results may be reported in hardcopy or should be reported electronically, and how data should be reported electronically.

Discussion of Proposed Changes

Today's proposed rule would make the requirement to assess the total accuracy of orifice-, nozzle-, and venturi-type fuel flowmeters from the transmitter/transducer test results an option. As an alternative, proposed section 2.1.6.5 in Appendix D would allow each of the three transmitters (static pressure, differential pressure, and temperature) individually to meet

an accuracy specification of 1.0 percent of the upper range value of the transmitter.

Today's rulemaking also proposes a procedure in section 2.1.6.1 of Appendix D for testing the accuracy of orifice-, nozzle-, and venturi-type fuel flowmeters. Each transmitter would be calibrated against NIST-traceable reference values at least once at the zero level and at a minimum of two other levels across the range of values that the transmitter reads during normal unit operation. Note that in many instances this would be a portion of the full-scale range of the transmitter, rather than the entire range. In addition, revised section 2.1.6.2 of today's proposed rule includes the new Equation D–1a to clarify how to calculate the error from an individual transmitter.

Finally, today's proposal would clearly specify the consequences of failure of an accuracy test on transmitters in section 2.1.6.5 of Appendix D. Just as CEM data are considered invalid from the time that a quality assurance test is failed until the test is subsequently passed, data from a fuel flowmeter would be considered invalid from the date and time of a failed transmitter accuracy test until the date and time of a passed transmitter accuracy test.

Rationale

The Agency considered two main options for determining the accuracy of a transmitter or transducer of an orifice-, nozzle-, or venturi-type fuel flowmeter. In the first approach (which is consistent with current policy guidance), these types of fuel flowmeters would be required to meet an accuracy of 2.0 percent of the upper range value of the total flow rate of the fuel flowmeter. The accuracy would be determined using the square root of the sum of the squares of all sources of error in the fuel flowmeter, according to the following equation:

$$\frac{dq_v}{q_v} = \left(K^2 + \left[\frac{-dP_f}{2P_f}\right]^2 + \left[\frac{d\Delta P}{2\Delta P}\right]^2 + \left[\frac{dT_f}{2T_f}\right]^2 \right)^{1/2}$$

Where: dq_v/q_v = Error in the volumetric flow rate due to transmitter drift at a given level;
K = Original error resulting from installation of orifice (including all other variables);
dP_f = Average difference between static pressure transmitter reading(s) and reference static pressure reading(s) at a given level;
P_f = Average reference static pressure reading at a given level;
$d\Delta P$ = Average difference between differential pressure transmitter reading(s) and reference differential pressure reading(s) at a given level;
ΔP = Average reference differential pressure reading at a given level;
dT_f = Average difference between temperature transmitter reading(s) and reference temperature reading(s) at a given level; and
T_f = Average reference temperature reading at a given level.

If the error calculations for error from the primary element of the fuel flowmeter were not available, then the facility could use a default value of 1.0 percent of the upper range value error from all parts of the fuel flowmeter except for the differential pressure, static pressure, and temperature transmitters. (In other words, the factor ''K'' in the equation above would be equal to 1.0 percent of the upper range value.) However, this would almost certainly trigger the requirement for recalibration or retesting of the accuracy of the transmitters in the next calendar quarter because the fuel flowmeter accuracy would exceed 1.0 percent of the upper range value. Based upon statements from the American Gas Association, it is the Agency's understanding that for an orifice-, nozzle-, or venturi-type fuel flowmeter meeting AGA Report No. 3 or ASME MFC–3M, the maximum error from portions of the meter other than the transmitters should be 1.0 percent of the upper range value (see Docket A–94–16, Item II–F–2, and this Docket, A–97–35, Item II–E–18).

In the second approach to determining error for orifice-, nozzle-, and venturi-type fuel flowmeters, each transmitter or transducer would be tested separately for accuracy, and each transmitter or transducer would be required to meet an accuracy specification of 1.0 percent of the full scale range of the transmitter. Under this approach, it would no longer be necessary to determine the total error in the flowrate from the fuel flowmeter. Because this proposal would eliminate the calculation of the total error in flowrate, there would no longer need to be a requirement to retest the accuracy of the transmitters in the next calendar quarter when the total fuel flowmeter accuracy exceeds 1.0 percent of the upper range value.

In today's rule, EPA proposes to allow both of the approaches described above for calculating the total flowmeter accuracy. The second approach (i.e., calculating individual transmitter accuracy) is simpler than calculating the total error in the flow rate, although it is less directly related to the accuracy of SO_2 mass emission rate and heat input measurements than the fuel flowrate. An individual transmitter accuracy specification of 1.0 percent of the full scale of each transmitter would be slightly stricter than a total fuel flowmeter accuracy specification of 2.0 percent of the upper range value of the fuel flowmeter, because one transmitter could potentially have an error greater than 1.0 percent of its full scale range while the entire error in the fuel flowrate would still be less than 2.0 of the upper range value of the fuel flowmeter. Thus, the option of calculating the total error in the fuel flowrate has been retained in today's proposal. At least one industry representative suggested allowing both approaches of calculating accuracy when testing transmitters of an orifice-, nozzle-, or venturi-type fuel flowmeter (see Docket A–97–35, Item II–E–24).

The Agency considered two main methodologies for transmitter testing on orifice-, nozzle-, and venturi-type flowmeters. The first method would be to require a five-point test that checks the linearity of the transmitter. The transmitter would be tested against an NIST traceable method (e.g., testing a pressure transmitter against an NIST traceable deadweight transmitter) at the following percentages of the full scale range of the transmitter: 0.0 percent, 20.0 to 30.0 percent, 40.0 to 60.0 percent, 70.0 to 80.0 percent, and 100.0 percent. This is the general approach that was taken by many utilities that provided transmitter calibration results to EPA (see Docket A–97–35, Items II–D–26 through 28).

The second method would be to require a comparison to an NIST traceable transmitter at the zero level and at least two other levels across the range of readings on the transmitter or transducer. This would be different from the first method in that the transmitter would only need to be tested across the range where the transmitter is

actually used. For example, if a fuel flowmeter transmitter's readings never rise higher than 60.0 percent of the full scale range of the transmitter, then the transmitter could be tested at 0.0 percent, 30.0 percent, and 60.0 percent of full scale. These procedures are reflected in the proposed revised section 2.1.6.1 of Appendix D.

The Agency is proposing the second method in today's rule, i.e., that each individual transmitter must be tested at three or more points across its normal range of readings. EPA realizes that it is standard industry procedure to test a fuel flowmeter at five levels across its entire range (see Docket A–97–35, Item II–E–24). However, the Agency is aware of at least one case where a fuel flowmeter failed to meet an accuracy specification of 2.0 percent of the upper range value when it was tested at 100.0 percent of the upper range value. However, the fuel flowmeter was never used to measure a rate greater than roughly 55.0 percent of the upper range value (see Docket A–97–35, Item II–D–15). If this flowmeter had only been required to test across the range where the fuel flowmeter actually measured fuel flow rates, it would have met the accuracy specification. Section 2.1.5 requires fuel flowmeters that are tested against a master fuel flowmeter to be tested across the range of measured fuel flowrate only. Requiring testing of each transmitter at three or more points across the range of all readings would still ensure that the transmitter reads accurately across all readings, while reducing the possibility that the transmitter might fail an accuracy test because of a high error reading at the high end of the transmitter's range where the transmitter is never used. At least one utility has mentioned that this would be helpful (see Docket A–97–35, Item II–E–24). The Agency solicits comment on the proposed approach.

Today's proposed rule also includes Equation D–1a for calculating error from an individual flowmeter transmitter. The Agency feels that this would clarify the calculation. It also would prevent the possible confusion that would occur if a facility attempted to use the existing Equation D–1, which is designed for a fuel flowmeter that is compared to another fuel flowmeter.

Finally, under today's proposal, when a transducer or transmitter test is failed, a fuel flowmeter would be considered out-of-control, and its data would be considered invalid until the date and time the transmitter is retested and meets an accuracy of 1.0 percent of its full scale.

(f) Reporting of Fuel Flowmeter Testing Data

Background

As mentioned above in Section III.P.5 of the preamble, utilities have had questions about how to report the results of their fuel flowmeter testing data. In certification applications and quality assurance testing results, utilities have reported test data in a variety of ways. In some cases, the Agency was unable to determine the flowmeter accuracy from the testing information provided because data were not labeled as reference flow rate data, flowmeter data, or accuracy data. For example, for turbine flowmeters, data on the reproducibility of the ''K-factor'' was often presented. However, these are not flow rate data, nor is it clear what the accuracy of the flow rate is (see Docket A–97–35, Item II–D–9). Sometimes data were presented in tables. Other data were presented in graphs (see Docket A–97–35, Item II–D–9). In many cases, Agency or state environmental agency staff needed to request additional information from utilities to determine if they had met the accuracy requirement for fuel flowmeters (see Docket A–97–35, Items II–C–3, II–C–5).

To clarify the requirements for certification applications for fuel flowmeters, the Agency issued policy guidance about the type of information to provide (see Docket A–97–35, Item II–I–9, Policy Manual, Question 12.27). This guidance included a sample table with an example of how to submit information for a fuel flowmeter that is tested against a master meter or flow prover reference value.

Discussion of Proposed Changes

EPA proposes to add a sample table to Appendix D (Table D–1) for summarizing the results of accuracy tests of fuel flowmeters that are calibrated by comparison against other fuel flowmeters or a prover. In addition, EPA proposes to add a separate table for summarizing the results of calibrations of the transmitters or transducers of an orifice-, nozzle-, or venturi-type fuel flowmeter.

Rationale

In today's proposed rule, EPA would provide clarification in the form of a table for summarizing the quality assurance test results of fuel flowmeters that are compared against other fuel flowmeters or a prover. A second table is provided for summarizing the results of calibrations of transmitters or transducers of an orifice-, nozzle-, or venturi-type fuel flowmeter. This second table accounts for differences in the testing procedure for transmitters or transducers. In both cases, EPA has tried to make clear what critical information would have to be reported in order to demonstrate that the fuel flowmeter (or the transmitter of an orifice-, nozzle-, or venturi-type fuel flowmeter) meets the accuracy specification. In addition, EPA will design revised electronic record types with this type of information so that test results may be more easily reported electronically. The Agency is aware that this has been difficult or confusing for some utilities (see Docket A–97–35, Items II–D–23, and II–I–9, Policy Manual, Question 12.27). The Agency also considered adding a sample graph for reporting accuracy data. However, EPA feels that it would be easier to compare the data in tabular format and to enter it into the electronic data format than to enter values from a graph. Most of the graphs provided to EPA have been relatively easy to read, and there appears to be less of a need for an example to be included in Appendix D (see Docket A–97–35, Item II–D–9).

7. Use of Uncertified Commercial Gas Flowmeter

Background

Currently, a facility using Appendix D may either install its own gas flowmeter or use a commercial gas flowmeter owned by a pipeline natural gas supplier, provided that the meter meets the reporting and accuracy requirements of Appendix D, including initial certification and continuing quality assurance requirements. Some utilities have suggested to EPA that they would like to be able to use data from the commercial billing of pipeline natural gas without having to demonstrate that the gas flowmeter meets initial certification and continuing quality assurance requirements (see Docket A–97–35, Items II–D–45, II–D–49). Those utilities assert that because the amount of gas measured is already subject to market forces, the monitoring should be sufficiently accurate for the Acid Rain Program. Utilities have mentioned that gas companies often are already conducting meter calibrations as quality assurance, but utility customers generally do not have access to this information (see Docket A–97–35, Items II–D–49, II–E–33). Facilities would find it advantageous to rely upon their commercial billing charges for accounting for pipeline natural gas usage because they would need to devote less time, effort, and money to the maintenance of gas fuel flowmeters. This is particularly desirable to facilities since the SO_2 emissions from pipeline

natural gas are extremely low compared to the SO_2 emissions from other fuels.

Discussion of Proposed Rule Changes

Proposed section 2.1.4.2 of Appendix D would allow facilities to record and report the gas flow rate, the heat input rate, and emission values based on gas flowmeter readings from a flowmeter used for commercial billing of pipeline natural gas without meeting the certification requirements of section 2.1.5 of Appendix D or the quality assurance requirements of section 2.1.6 of Appendix D under specified conditions. Relief from the certification and quality assurance requirements for gas flowmeters used for commercial billing would be limited to flowmeters where the gas flowmeter is used for commercial billing under a contract with another company having no common owner with the unit(s) served by the flowmeter, which would exclude any gas flowmeters used for transfers of gas between different divisions, subsidiaries, or affiliates of the same company.

If the commercial billing gas flowmeter would be used without undergoing certification or quality assurance under part 75 requirements, then the designated representative would need to report hourly records of the gas flow rate, the heat input rate, and emissions due to combustion of pipeline natural gas, as well as heat input rate for each unit if the commercial billing gas flowmeter is on a common pipe header. This would be similar to the reporting currently done for a certified gas flowmeter, but no quality assurance records would be required. The quarterly report would contain record types 303 for fuel flow rate and heat input rate, record type 314 for the SO_2 mass emission rate, either record type 320 or 323 for the NO_X emission rate in lb/mmBtu, and either record type 330 or 331 for CO_2 mass emissions. It also would be necessary for the designated representative to identify the commercial billing gas flowmeter in Table B (electronic record type 510) of the monitoring plan for the unit.

So long as the records from the commercial billing gas flowmeter are the values used for commercial billing, the designated representative would report those values from the commercial billing gas flowmeter without adjustment. If the records from the commercial billing gas flowmeter are not consistent with the values used for commercial billing because of some problem that needs to be reconciled between the gas vendor and the facility customer, then the designated representative would consider the readings from the commercial billing gas flowmeter to be invalid for that billing period and would report hourly records using the missing data procedures for fuel flowmeter data found in section 2.4 of Appendix D for all hours of gas combustion during that billing period. A facility would not be able to use the commercial billing value in the quarterly report if the commercial billing value was different from the value on the commercial billing gas flowmeter.

Rationale

Utilities have suggested that the purchase of pipeline natural gas from a vendor is subject to market forces that ensure accurate monitoring (see Docket A–97–35, Item II–D–49). Utilities have stated that gas vendors already have procedures for certification and meter calibration and that the gas vendors have an even greater incentive than utilities to maintain a high monitor ''uptime'' (i.e., availability) for gas fuel flowmeters. Typically, utilities will work together with their gas vendors if they believe there is any sort of discrepancy in their monthly billing for pipeline natural gas (see Docket A–97–35, Items II–D–33, II–E–33).

The Agency believes that this argument is reasonable. However, EPA also understands that some utilities require their gas vendor to correct their billing values based upon the evidence of the utility's own gas flowmeters. In addition, it is likely that utilities will be combusting more pipeline natural gas in the future as they respond to current and potential future environmental requirements for reducing NO_X and CO_2. Therefore, the Agency believes that there must be conditions placed upon reporting emissions and heat input for the Acid Rain Program from gas flowmeters used for commercial billing if the gas flowmeters will not be required to meet the certification and quality assurance requirements of part 75.

The Agency is proposing to limit the waiver from certification and quality assurance requirements to commercial billing gas flowmeters that are used in billing transactions between companies with entirely different ownership (e.g., a pipeline natural gas vendor and a separate electric utility company with no owners in common). Some utilities requested the relief from quality assurance requirements based upon the reasoning that a gas vendor would do its own quality assurance and maintenance, and perhaps with better accuracy than a utility would be able to maintain, but the utility would not necessarily have access to the test results and would not have control over what quality assurance might occur (see Docket A–97–35, Items II–D–49, II–E–33). This reasoning is sound if the utility and the gas vendor have no common owners, but it would not necessarily be sound if a gas supplier were part of the same company as the electric utility. Also, utilities suggested that a gas vendor may have an incentive to overstate the amount of gas in order to bill more, rather than having an incentive to underestimate or under-report (see Docket A–97–35, Item II–D–49). Once again, this argument is reasonable if the gas vendor is a separate entity, but may not be reasonable if the gas supplier has common owners with the electric utility. Therefore, today's proposed rule includes a limitation on the waiver from certification and quality assurance requirements for commercial billing gas flowmeters to those gas flowmeters used for commercial billing between companies with separate ownership.

EPA solicits comment on the proposed approach of allowing the use of uncertified fuel flowmeters for purposes of determining emissions and heat input in the limited circumstances described above.

EPA has proposed in today's rule that a facility may only report data from a commercial billing gas flowmeter if the data are used in a commercial transaction. A group of utilities suggested that the Agency allow facilities to report quarterly SO_2 emissions based on gas supplier data, including any reconciliation that has taken place (see Docket A–97–35, Item II–D–45). Such a reconciliation between a gas vendor and its customer may occur if the customer believes there is a discrepancy in their monthly billing for pipeline natural gas (see Docket A–97–35, Items II–D–33, II–E–33). If a facility and its gas vendor determined that gas supply information from a fuel flowmeter were not sufficiently accurate to purchase gas, then the Agency presumes the gas supply information is also not sufficiently accurate for emissions accounting.

The Agency also considered whether a facility should be able to use the reconciled gas volumes agreed upon for billing if that value were not from the commercial billing gas flowmeter. In general in the Acid Rain Program, hand-typed corrections to emissions data are not permitted (see Docket A–97–35, Item II–I–14), with the primary exception of cases where sound engineering judgement indicates there is an obvious error that cannot exist, such as a negative concentration reading.

Allowing a facility to enter a commercial billing value by hand would contradict this basic reporting policy of the Acid Rain Program.

Today's proposed rule also specifies the type and frequency of information that would be required to be reported by a facility concerning pipeline natural gas. Some utilities have requested the ability to report only a quarterly cumulative SO_2 mass emission number for emissions from gas (see Docket A–97–35, Item II–D–45). However, the Agency believes that there are several reasons for maintaining hourly heat input rate and emissions data during combustion of pipeline natural gas. First, hourly data is the most useful interval of data for air quality modeling in order to see if progress is being made in reducing emissions. Hourly data from combustion of pipeline natural gas will become even more important as more units switch to combusting pipeline natural gas in order to reduce their emissions. In addition, hourly data are easier to check for anomalous values than quarterly data. Further, hourly heat input rate data is necessary in order to determine the NO_X emission rate when using the NO_X-versus-heat input rate correlation of Appendix E to part 75. Also, since hourly data are already being recorded, reported, and processed by automated computer data acquisition and handling systems, a change to this requirement would require costly reprogramming for industry and for EPA. For all of these reasons, EPA is proposing that facilities continue to report hourly gas flow rates, heat input rates, and emissions from commercial billing gas flowmeters that are not required to meet the certification and quality assurance requirements of part 75.

Q. Appendix G

1. Use of ASTM D5373–93 for Determining the Carbon Content of Coal

Background

Appendix G to part 75 provides procedures for determining CO_2 emissions from fuel sampling and analysis instead of from a CO_2 CEMS and a flow monitor. Section 2.1 of Appendix G includes a mass-balance equation for determining CO_2 (see Equation G–1), the frequency for sampling fuel, and the specific methods for analyzing fuel for carbon content. Section 2.3 of Appendix G provides a method for determining CO_2 mass emissions from a gas-fired unit from its heat input using Equation G–4. Some facilities use Appendix G procedures to determine CO_2 mass emissions every day for their units. Other facilities might use the procedures of section 2.1 of Appendix G only to provide CO_2 mass emissions during extended periods when CO_2 data are missing from their CO_2 CEMS, under the provisions of § 75.36.

A utility and its fuel analysis laboratory contacted EPA concerning use of an additional ASTM method for analysis of carbon content. The industry staff felt that the new infrared analysis method, ASTM D5373–93, was the most up-to-date method and that this method should be at least as accurate as the methods specified in Appendix G to part 75 (see Docket A–97–35, Item II–D–25). Based upon the precision and bias information in the method, EPA approved its use under § 75.66 (see Docket A–97–35, Item II–C–16).

Discussion of Proposed Changes

Today's proposed rule would allow the use of ASTM D5373–93, ''Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke,'' for Section 2.1 of Appendix G to part 75. This method is for determining the carbon content of coal. ASTM D5373–93 would also be incorporated by reference in § 75.6. Facilities would also continue to have the option to use ASTM D3178–89 to analyze coal for carbon content.

Rationale

EPA has previously approved the use of ASTM D5373–93 for analyzing the carbon content of coal (see Docket A–97–35, Item II–C–16). The Agency believes this method is of sufficient accuracy for use in the Acid Rain Program. In addition, EPA historically has accepted analytical methods from standard-setting organizations such as the American Society for Testing and Materials (ASTM). The Agency solicits comment on the use of ASTM D5373–93 for analyzing the carbon content of coal.

2. Changes to Fuel Sampling Frequency

Background

Section 2.1 of Appendix G (as revised by the May 17, 1995 direct file rule) specifies that fuel sampling should be done weekly for gas or oil for each shipment for diesel fuel and at least once per month for gaseous fuel. The sampling frequencies for diesel fuel and for gaseous fuel are consistent with the frequency for sampling under Appendix D to part 75.

Most gas-fired and oil-fired units that perform fuel sampling for sulfur content under Appendix D also perform fuel sampling for carbon content. Today's proposed rule would reduce the frequency with which facilities need to sample oil or gas under Appendix D.

Discussion of Proposed Changes

The fuel sampling frequency specified in section 2.1 of Appendix G would be made consistent with the proposed requirements for Appendix D oil and gas sampling. Thus, all oil samples could be taken upon delivery, either from the delivery vessel itself or from the storage tank after a delivery is transferred. Gas samples would be taken monthly (for pipeline natural gas), for each shipment (for gases delivered in lots), or daily (for fuels that are analyzed daily for sulfur). Coal samples would continue to be taken weekly.

Rationale

Appendix D of today's proposed rule would reduce the required sampling frequency of oil and gaseous fuels delivered in lots. Based upon information provided by one utility, the variability of carbon content in oil is less than the variability of sulfur content (see Docket A–97–35, Item II–D–18). Some utilities have stated that they would prefer the procedures for sulfur and GCV to be similar (see Docket A–97–35, Item II–D–24). Based upon this statement, the Agency believes that facilities would also prefer to have consistent fuel sampling procedures for Appendices D and G. Therefore, the Agency believes it is appropriate to make the fuel sampling frequency for carbon analysis under Appendix G consistent with the fuel sampling frequency for sulfur content under Appendix D. Similarly, section 5.5 of Appendix F would be revised to make the gas sampling frequency consistent with Appendix D. The Agency solicits comment on the proposed changes to the fuel sampling frequency.

3. Addition of Missing Data Procedures for Fuel Analytical Data

Background

Appendix D provides procedures for substituting missing fuel analytical information, either for sulfur or GCV. However, Appendix G to part 75 does not specify what should be done if carbon content data are missing.

Some software programmers asked EPA what missing data procedures should be used for carbon content data (see Docket A–97–35, Item II–E–5). The Agency responded to this question at a public conference and in policy guidance (see Docket A–97–35, Items II–E–5, and II–I–9, Policy Manual, Question 6.3). In its policy guidance, EPA stated that facilities should ''[f]ill in the most recent carbon content . . . available for that fuel type (gas, oil or

coal) of the same grade (for oil) or rank (for coal). If at all possible, use a carbon content value from the same fuel supply.''

Discussion of Proposed Changes

Today's proposed rule would allow facilities to substitute for missing carbon content prior to January 1, 2000, using either the most recent carbon content for that fuel type, grade and rank, or procedures parallel to those of Appendix D. Beginning January 1, 2000, facilities would substitute for missing carbon content data using procedures consistent with Appendix D. For gaseous fuels and for oil sampled manually, these procedures would provide for a conservative maximum carbon content value. Specifically, the permissible conservative carbon content values would be either the maximum carbon content measured in the previous calendar year or, if this information were not available, a default value based upon handbook fuel characteristics. For weekly coal samples or composite oil samples, CO_2 mass emissions would be calculated using the highest carbon content from the previous four carbon samples available.

Rationale

Software programmers have already indicated that it is useful to have a procedure for filling in missing carbon content data for purposes of programming (see Docket A–97–35, Item II–E–5). Some utilities have stated that they would prefer the missing data procedures to be similar for both sulfur and GCV, even if both values are conservative (see Docket A–97–35, Item II–E–24). Therefore, the Agency believes that facilities would also prefer to have Appendix G missing data procedures for carbon content that are parallel with those for sulfur content and GCV in Appendix D. Thus, today's proposal would allow for missing data for manual oil samples or for gaseous fuel using the maximum carbon content measured in the previous calendar year or, if this information were not available, a default value based upon handbook fuel characteristics.

In determining the conservative default carbon content values that would be used for missing data substitution in the event that no previous carbon content samples are available, the Agency consulted several handbook reference tables on fuel characteristics. Specifically, the Agency reviewed handbook values for the carbon content of coal (of various ranks), oil (of various grades), and gas (of different types). (see Docket A–97–35, Items II–I–18, II–I–19, II–I–20). In the case of coal, there was a fairly wide range of carbon content values for different ranks of coal. Therefore, today's rule would propose separate default carbon content values for Anthracite, Bituminous, and Subbituminous/Lignite. In contrast, the carbon content values for different grades of residual oil were fairly consistent. For this reason, today's rule proposes a single default carbon content value for all grades of oil. Finally, for gaseous fuels, the handbooks which were reviewed presented a fairly narrow range of values for natural gas but a much wider range of values for other types of gaseous fuels. Therefore, today's rule proposes a value for natural gas and a separate, conservative value for all other types of gaseous fuels.

The Agency solicits comment on the proposed revisions to the missing data procedures under Appendix D.

R. Reporting Issues

1. Partial Unit Operating Hours and Emission and Fuel Flow Rates

Background

For affected units that use CEMS to account for emissions under part 75, hourly emission rates of SO_2 (in lb/hr), NO_X (in lb/mmBtu), and CO_2 (in tons/hr), and hourly heat input rates (in mmBtu/hr) are calculated using the applicable equations in Appendix F. For affected units that use fuel flow meters and fuel analysis (or default emission rates) rather than CEMS, the applicable equations in Appendices D, F and G (for certain gas-fired units) are used to determine the hourly SO_2 and CO_2 mass emission rates and heat input rates. For oil and gas-fired peaking units that use Appendix E to account for NO_X emissions, the hourly NO_X emission rates in lb/mmBtu are derived from a graph of NO_X emission rate versus heat input rate, the hourly heat input rates being derived from the applicable equation in Appendix F. Under § 75.54(b)(2), unit operating time is reported by rounding the actual operating time up to the nearest 15 minutes.

The equations in Appendices D through G assume that each unit operating hour consists of a full 60 minutes of unit operation (or, for common stacks, that emissions are discharged through the stack for 60 minutes in each hour); the equations do not attempt to account for partial unit operating hours. This is a shortcoming in the current rule, because partial unit operating hours sometimes occur during periods of unit startup, shutdown, and malfunction. Therefore, to ensure accurate accounting of SO_2 and CO_2 mass emissions and unit heat input, part 75 should address the issue of partial unit operating hours. Note, that because NO_X emission rates are measured with respect to heat input (lb/mmBtu), rather than with respect to time (lb/hr), this discussion is not relevant for NO_X emission rate. Many vendors and utilities have asked EPA for guidance on how to calculate mass emission rates during partial unit operating hours (see, e.g., Docket A–97–35, Item II–D–4).

The crux of the partial unit operating hour issue is when to adjust the emission data for unit operating time, before the reporting of hourly values or at the quarterly summation. For many units, there are very few hours of partial operation, and adjusting the data for operating time merely involves multiplying by 1, a seemingly inconsequential issue. For other units, such as peaking and cycling units, which start up and shut down often, the issue of how the data is reported is relevant because there can be a significant amount of partial unit operating hours. Definitive and standardized reporting requirements allow facilities and/or vendors to program their software such that their calculated result equals the result calculated by EPA.

For SO_2 and CO_2, the question is whether to report hourly emissions on a mass basis (i.e., lb or tons) or on a mass emission rate basis (i.e., lb/hr or tons/hr). For heat input, the question is whether to report the total hourly heat input (in mmBtu) or the hourly heat input rate (in mmBtu/hr). For example, suppose that a unit emits for a full 60 minutes in a particular clock hour at an SO_2 concentration of 602.5 parts per million (ppm), a CO_2 concentration of 10.0 percent, a volumetric flow rate of 4,000,000 standard cubic feet per hour (scfh), and a heat input rate of 300 mmBtu/hr. Suppose further that the same unit operates for only 15 minutes in the next hour and all of the parameters (i.e., SO_2 and CO_2 concentration, flow rate, and heat input rate) remain unchanged. If unit operating time is disregarded, the SO_2 mass emission rate (calculated from Equation F–1 in Appendix F) would be the same (400 lb/hr) for both the partial operating hour and the full unit operating hour. Similarly, the CO_2 mass emission rate would be the same (22.8 tons/hr) and the heat input rate would be the same (300 mmBtu/hr) for both the full and partial operating hours. The mass emission rates and heat input rate for the partial unit operating hour are the same as the full-hour values because they are based solely upon data recorded during unit operation, i.e., in

the first 15 minutes of the hour. The hourly average rates for the partial hour do not include ''zero'' values for the three 15-minute periods of unit non-operation during the clock hour (e.g., an SO_2 emission rate of (400 lb/hr + 0 + 0 + 0)/4 = 100 lb/hr would not be appropriate). If the emission and heat input rates are adjusted by multiplying them by the operating time, then, for the full operating hour (i.e., operating time = 1.0), the SO_2 and CO_2 mass emissions and heat input would be, respectively, 400 lb SO_2, 22.8 tons CO_2, and 300 mmBtu. For the partial hour (operating time = 0.25), the corresponding values would all be divided by four, i.e., 100 lb SO_2, 5.7 tons CO_2, and 75 mmBtu, respectively.

Software vendors and utilities have requested clarification as to whether hourly SO_2 mass emission values should be reported as totals, in lb, or as rates, in lb/hr. As early as November of 1993, EPA stated that hourly SO_2 mass emission values should be reported as rates in lb/hr. Then, when determining quarterly cumulative SO_2 mass emissions, each hourly emission rate would be converted to a mass basis by multiplying it by the unit operating time (expressed as a fraction of an hour) for the same hour. Similarly, hourly heat input values would be expressed as rates, in mmBtu/hr, and hourly CO_2 mass emissions would be expressed as rates, in tons/hr. Parallel issues were also addressed by the Agency's policy, for units that determine SO_2 and CO_2 mass emissions and heat input from fuel flow rates and fuel analyses under Appendix D to part 75 (see Docket A–97–35, Item II–I–9, Policy Manual, Questions 14.14, 14.36 and 14.37).

Some utilities have requested that the Agency change its policy and allow reporting of hourly total SO_2 and CO_2 mass emissions and heat input instead of mass emission rates and heat input rates (see Docket A–97–35, Item II–E–14). The utilities argued that this would simplify determination of the total year-to-date SO_2 mass emissions, in order to estimate the number of allowances needed to cover a unit's emissions or to prepare a report on mass emissions for a state environmental agency, because the reported values would already be multiplied by the hourly operating time. Thus, by performing the multiplication by operating time before reporting the hourly value rather than waiting until calculating the quarterly value, it might save a calculation step if a facility wanted to use the data for another purpose. For these reasons, reporting of totals is a preferred approach for some facilities. However, other utilities that have incorporated the correct rate approach into their software have indicated that they would prefer not to have to revise their software to report in totals.

Partial unit operating hours must also be considered in the recording and reporting of hourly unit load. The standard missing data procedures in § 75.33 require historical flow rate data to be placed in load ''bins'' (ranges) based upon the maximum operating electrical generation (or steam flow rate) of the unit. However, the recorded hourly volumetric flow rate value in scfh applies only to the fraction of the hour in which the unit operates. Therefore, the reported load for the hour should be based upon the average electrical generation during the period when the unit operates. Thus, the electrical generation should be recorded as a rate for the period when the unit operates, rather than an integrated total for the entire hour. The units for reporting hourly load should, therefore, be MWe or 1000 lb/hr of steam, and not MW-hr or 1000 lb of steam.

Discussion of Proposed Changes

In today's rulemaking, EPA is proposing to amend part 75 to clarify that heat input, fuel flow, SO_2 mass emissions, and CO_2 mass emissions are all to be reported on an hourly basis as rates. Today's proposal also would clarify that the hourly emission rates are to be based only upon data collected during periods of unit operation (i.e., for partial unit operating hours, emission rates or heat input rates of zero that are recorded during periods of non-operation are not to be included in the hourly average emission rates). These clarifications are found in proposed § 75.57, and Appendices D, E and F to part 75. Today's proposed rule would also clarify that the proper units of reporting for load are MWe and lb/hr of steam.

Today's proposal would also provide new options for reporting unit operating time. While the current requirement to report operating time rounded to the nearest 15 minutes would be retained as an option, the proposal would allow more flexibility by specifying that, for reporting purposes, unit operating time be rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

Consistent with the requirement to report hourly SO_2 and CO_2 mass emissions and hourly heat input as rates, today's rulemaking proposes to revise the quarterly summation formulas for SO_2 and CO_2 and to add summation formulas for heat input in Appendix F to part 75. The proposed formulas show that hourly mass emission rates or heat input rates would be multiplied by unit operating time before summing to get total mass emissions. Today's proposal also includes new formulas in Appendix D for summing hourly SO_2 mass emission rates and hourly heat input values from fuel flowmeter systems in order to determine quarterly and annual total SO_2 mass emissions and total heat input. The Appendix D and F equations revised or added to address summations include Equations D–6, D–7, D–8, D–9, F–3, F–12, F–24, and F–25.

In addition, EPA is proposing optional recordkeeping provisions for determining total heat input, total SO_2 mass emissions or total CO_2 mass emissions for the hour. In addition to reporting the required emission and heat input rates, owners or operators could choose to report the total hourly heat input and mass emissions under this option.

Rationale

As stated above, some utilities have expressed a preference for reporting hourly total values for SO_2 and CO_2 mass emissions and heat input, rather than rates (see Docket A–97–35, Item II–E–14). They have stated that this is easier to understand and that reporting hourly total values, instead of or in addition to rates, would make it easier to determine the cumulative total mass emissions at any time during the year.

One representative requested that EPA consider allowing either method of calculation (i.e., hourly rates or totals), so long as the annual mass emissions and heat inputs are correctly determined and reported. EPA notes that, although this approach may appear advantageous because it would not require some facilities to reprogram their DAHS software, it would require other facilities to reprogram their software and it would make it difficult for EPA to verify emissions calculations from reported hourly data. Because EPA considers it essential to the Acid Rain Program to be able to recalculate annual compliance values based upon hourly emission information reported by facilities, the Agency is not revising the rule to take the representative's suggestion. EPA considered using the total mass emissions (or total heat input) approach instead of the mass emission rate (or heat input rate) approach currently stated in Agency policy (see Docket A–97–35, Item II–I–9, Policy Manual, Questions 14.14 and 14.36). In fact, as discussed in section III.H. of this preamble, the Agency is proposing, under subpart H of part 75, model

reporting requirements for NO_X mass emissions that would (if adopted by an applicable state or federal authority) require hourly NO_X mass emissions to be reported as a total value (in lb) rather than an hourly mass emission rate (in lb/hr). However, using hourly mass emission totals for values currently reported to the Agency would have the distinct disadvantage of requiring both EPA and the utilities who correctly implemented the mass emission rate approach to reprogram software to perform the new calculations, whereas retaining the use of SO_2 and CO_2 emission and heat input hourly rates offers several advantages.

First, using hourly mass emission rates and heat input rates instead of totals is consistent with the units of measure in which flow rate is recorded. Volumetric flow monitors measure flow rate during a given time in standard cubic feet per hour scfh, rather than total flow in standard cubic feet (scf). When SO_2 concentration is multiplied by volumetric flow rate, one calculates a mass emission rate rather than a total mass of SO_2. Similarly, multiplying a volumetric flow rate by a diluent gas concentration yields a heat input rate in mmBtu/hr, rather than a total heat input in mmBtu.

Second, the current missing data procedures for volumetric flow rate, which are based upon the assumption that flow is a rate that is comparable from one hour to another, rather than a total volumetric flow that will vary depending upon the unit operating time, would no longer be appropriate if volumetric flow rate were changed to a total volumetric flow. Third, for Appendix E gas-fired or oil-fired peaking units, it is critical that heat input rate, and not total heat input, be used to determine the NO_X emission rate. The Appendix E correlation curve formulas are based upon heat input rate rather than total heat input. Appendix E allows a facility to create a correlation of the NO_X emission rate measured in the stack during stack testing and heat input combusted during that same period of time, rather than installing CEMS on gas-fired or oil-fired peaking units. If a facility were mistakenly to use the total heat input from an hour rather than the heat input rate, it would correlate to the wrong portion of the NO_X to heat input rate correlation curve and would incorrectly estimate NO_X emission rate. For example, if heat input totals were used to determine NO_X emission rate from the Appendix E curve, the unit would have a different NO_X emission rate if it combusted 25,000 mmBtu in half an hour than if it combusted 25,000 mmBtu during a full hour. This would apply both under the current provisions of Appendix E and today's revised provisions to Appendix E.

In view of the above considerations, today's proposed rule would affirm that facilities are to report SO_2 and CO_2 emissions and heat input as rates on an hourly basis. However, facilities would also be allowed, at their discretion, to report SO_2 and CO_2 emissions and heat input as hourly totals, in addition to reporting them as rates. This approach would not require reprogramming of computerized reporting software for those utilities that are following EPA's current policy, and would provide consistent reporting that allows EPA to recalculate emissions and heat input values. Those utilities that find recording and reporting of hourly total SO_2 and CO_2 mass emissions and heat input to be desirable would be able to do so. EPA will provide the necessary electronic record types to support this optional reporting.

Although today's proposed rule would affirm that emissions and heat input are to be reported as rates, rather than totals, EPA has become concerned that for partial unit operating hours, some utilities are incorrectly calculating hourly average flow rates by including flow rates of zero in the hourly average to represent periods of non-operation, rather than basing the average flow rate solely on the minutes of operation of the affected unit during the clock hour. In one example, it appears that the software is designed to calculate the average flow rate by including data from all minutes during those fifteen-minute quadrants of an hour when the unit operates, thus including some minutes when the unit is not operating, rather than creating an average flow rate just from merely those minutes when the unit is operating and emitting (see Docket A–97–35, Item II–C–17). EPA suspects that still other utilities may be calculating an average hourly flow rate that includes flow rates of zero for whole quadrants of an hour when a unit does not operate. This can result in the flow rate values for partial operating hours being under-reported to EPA and a lowering of the average flow rates in the load ranges used to provide substitute flow rate data, both of which can cause underestimation of SO_2 mass emissions.

The Agency is also concerned that this same kind of improper data averaging may be occurring when hourly gas concentrations are determined during partial operating hours. EPA would, therefore, require in today's proposal that facilities base all of their reported hourly average concentrations, flow rates, emission rates, and heat input rates solely upon data that are recorded during unit operation (that is, when the unit is combusting fuel and emitting).

Some utilities have indicated that the approach of averaging in readings of zero from periods of non-operation has been incorporated to compensate for having to report operating time rounded up to the nearest fifteen minutes (Note, this is not an acceptable approach). A utility representative indicated that reporting operating time to less precision can cause overestimation of emissions because the operating time is multiplied by the mass emission rate. Thus, a mass emission rate of 400 lb/hr measured over a period of 20 minutes, during an hour when the unit shut down, would be multiplied by an operating time of .5 hr (i.e., 20 minutes rounded up to the nearest fifteen minutes) and would result in 200 lb of SO_2 being reported rather than the 132 lb of SO_2 that was actually emitted. The utility suggested that a solution would be to allow operating time to be reported to more precision than is currently allowed. Therefore, today's proposal would allow flexibility for reporting unit operating time to greater precision. While the current requirement to report operating time rounded up to the nearest 15 minutes would be retained as an option, the proposal would allow more flexibility by specifying that unit operating time be rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). Thus, a facility could decide whether it had enough partial operating hours (e.g., unit start-ups and shutdowns) to merit changing their software to report operating time to more precision.

2. Use of Bias-Adjusted Flow Rates in Heat Input Calculations.

In late 1995, the first year of the Phase I SO_2 allowance program, EPA conducted an audit of the Phase I-affected units. Data from the second quarter of 1995 were retrieved from the Emission Tracking System (ETS) in order to determine whether the SO_2 emission rates and heat input values were being properly reported. The results of the audit showed that a number of sources were not reporting heat input correctly. The problem in most instances was that the unadjusted flow rate was being used in the heat input equation, rather than the bias-adjusted value. EPA believes that this is attributable to the fact that part 75 does not explicitly state that the bias-adjusted flow rate is to be used in heat input

calculations. The Agency has attempted to clarify this through policy guidance (see Docket A–97–35, Item II–I–9, Policy Manual, Question 14.81). To correct the situation, the necessary language would be added to section 7.6.5 of Appendix A in today's proposed rule.

3. Removing the Restriction on Using the Diluent Cap Only for Start-Up

Background:

Based on the May 17, 1995 direct final rule, sections 3.3.4, 4.1, 4.4.1, 5.1, 5.2.1, 5.2.2, 5.2.3, and 5.2.4 of Appendix F currently provide for the substitution of a constant CO_2 or O_2 value for a measured value from a CO_2 or O_2 monitor during unit start-up. This provision was originally created in response to concerns from some utilities that their NO_X emission rate in lb/mmBtu was being overestimated during unit start-up (see Docket A–90–51, Item IV–D–220, Letter from English, Mark G., Deputy General Counsel, Kansas City Power & Light Company on EPA's Proposed Part 75 regulations; see also Docket A–94–16, Item II–F–2). During unit start-up or other periods when the unit is at a low load level, CO_2 concentrations are lower than during normal operation and O_2 concentrations are higher than during normal operation. The NO_X emission rate equation, however, is not designed to be used in these situations because it assumes complete combustion and normal operating conditions. As a result, the NO_X emission rate equation overestimates the NO_X emission rate when the CO_2 concentration is very low or the O_2 concentration is very high, such as during start-up. The equations for calculating emission rates in lb/mmBtu use measured CO_2 concentration or the difference between ambient air's O_2 concentration and the measured O_2 concentration in the denominator. For example, NO_X emission rate is calculated using a NO_X pollutant concentration monitor and a CO_2 diluent monitor using the following equation:

$$E_{NO_X} = 1.194 \times 10^{-7}\ C_{NO_X}\ F_c \frac{100}{\%CO_2}$$

When a small CO_2 concentration is entered into this equation, the calculated NO_X emission rate will be very high and will overestimate the actual emissions.

The idea of capping CO_2 or O_2 concentration was implemented in part 75 for determination of NO_X emission rate, CO_2 mass emissions, and heat input during unit start-up. The cap concentration was set at a minimum CO_2 concentration of 5.0 percent CO_2 and a maximum O_2 concentration of 14.0 percent O_2, based upon some information provided by utilities for boilers (see Docket A–94–16, Item II–D–34).

Some utilities asked EPA to consider extending this cap on diluent gas concentrations to other situations when a unit is operating at a low level (see, e.g., Docket A–97–35, Items II–D–20 and 30, and Docket A–97–35, Items II–E–13 and II–E–14). In addition to unit start-up, this might include periods of unit shutdown or unit ''banking,'' where a unit is combusting a very small amount of fuel to keep the boiler warm, but little or no electricity is generated. During these other situations where a unit operates at a low level, the CO_2 concentration will be very low and the O_2 concentration will be very high, resulting in high calculated NO_X emission rate values like those during unit start-up. One software vendor specifically mentioned that it would be easiest to implement the diluent cap if it could be used any time the CO_2 concentration would fall below or the O_2 concentration would rise above the cap value (see Docket A–97–35, Item II–E–7). This could be implemented mathematically in the software, rather than having to examine the unit operation or the number of hours since the unit started operating in order to trigger use of the diluent cap.

During the process of implementing the May 17, 1995 direct final rule, EPA issued guidance that explained that facilities may use the diluent cap values for calculating NO_X emission rate during unit start-up whenever the CO_2 concentration is below 5.0 percent or the O_2 concentration is above 14.0 percent, and also may use the actual measured CO_2 or O_2 concentration values at all times for calculating CO_2 mass emissions or heat input (see Docket A–97–35, Item II–I–9, Policy Manual, Question 14.39). In Question 14.39, EPA recommended that even if the diluent cap is used to calculate NO_X emission rate, the actual diluent measurement should be used for the purpose of calculating CO_2 mass emissions or heat input, because the purpose of the diluent cap was ''to avoid using an extreme diluent concentration in the denominator of the equation to calculate emission rate in lb/mmBtu.'' The formulas for calculating hourly CO_2 mass emission rate or hourly heat input rate do not use the CO_2 or O_2 concentrations in the denominator of the equation. Thus, use of the diluent cap would tend to overestimate both CO_2 mass emission rate and hourly heat input.

Discussion of Proposed Changes

Today's proposed rule would allow facilities to use diluent cap values of 14.0 percent O_2 or 5.0 percent CO_2 for boilers and 19.0 percent O_2 or 1.0 percent CO_2 for turbines. For the purpose of calculating NO_X emission rates in lb/mmBtu, the diluent cap would be allowed to be used for any hour in which the average measured CO_2 concentration is below the cap value or the average measured O_2 concentration is above the cap value. Diluent cap values would still be allowed to be used to calculate CO_2 mass emissions or heat input, as well as NO_X (or SO_2) emission rate in lb/mmBtu.

Rationale

EPA acknowledges that there are periods of low unit operation or low load in addition to unit start-up where the calculated NO_X emission rate would be overestimated if it were based upon measured diluent concentrations. Therefore, the Agency believes that extending use of the diluent cap is appropriate. The Agency believes that allowing use of the diluent cap anytime when the actual measured value is above the cap (for O_2) or below the cap (for CO_2) is easier to program and to implement than limiting the use of the diluent cap based upon unit load, another option that EPA considered. The Agency believes that it is unlikely that a unit would ever be able to operate at a high load and still have an O_2 or CO_2 concentration beyond the diluent cap value. Therefore, it is not necessary to limit the use of the diluent cap value based on unit load.

The Agency is also proposing new diluent cap values for turbines. Turbines tend to operate with much higher levels of excess O_2 than boilers. For example, Method 20 of Appendix A, 40 CFR part 60, the procedure for testing SO_2, NO_X and diluent gas from stationary gas turbines subject to the NSPS, requires testers to correct data to a typical concentration of 15.0 percent O_2. Emissions data reported to EPA confirms that for turbines, hourly concentrations of O_2 are typically between 14.0 and 16.0 percent and hourly concentrations of CO_2 are typically between 3.0 and 4.0 percent. Thus, a turbine's diluent gas concentration is likely to consistently exceed the diluent cap value of 14.0 percent O_2 and to be consistently below the cap value of 5.0 percent CO_2 promulgated in the May 17, 1995 direct final rule. If these values were allowed to be used by turbines at all times rather than just during unit start-up, a turbine

could conceivably report its NO_X emission rate using only the diluent cap value and never report the actual monitored diluent concentrations, thereby consistently underestimating the NO_X emission rate. Therefore, today's proposal provides diluent cap values of 19.0 percent O_2 or 1.0 percent CO_2 that are clearly beyond the typical O_2 or CO_2 concentrations measured at turbines, while still providing some relief at extreme diluent concentrations. It is EPA's observation that turbines with NO_X CEMS have not reported emissions using the diluent cap thus far. Thus, no turbines should need to reprogram software in order to report the use of the new diluent cap value for turbines with a new method of determination code.

EPA considered removing the option for facilities to use the diluent cap for heat input rate and CO_2 concentration, as well as for NO_X (and SO_2) emission rate in lb/mmBtu, but is not proposing to do so in today's proposal. As explained previously, the diluent cap was created in order to calculate more representative NO_X emission rate data during certain unusual circumstances. However, when a diluent cap value is used to calculate the hourly CO_2 mass emission rate or the heat input rate, the final calculation would often be less representative of actual emissions or heat input during those hours. The Agency also found that allowing some facilities to use the diluent cap only for NO_X emission rate and others to use the diluent cap also for hourly CO_2 mass emission rate and heat input rate makes it difficult to check emissions and heat input rate data to verify that calculations are performed correctly. This is because a data acquisition and handling system could use either the actual reported diluent gas concentration or the diluent cap value to calculate NO_X emission rate, CO_2 mass emission rate, or heat input rate, but there is currently no provision in the electronic data reporting format for a facility to indicate which value was used to calculate the heat input. However, some utilities have indicated that making a change to discontinue using the diluent cap for calculations of heat input rate and CO_2 mass emission rate would require a significant change in their software calculations (see Docket A–97–35, Item II–E–25). Therefore, today's proposed rule would allow facilities the options of (1) not using the diluent cap at all, (2) using the diluent cap only for calculating NO_X (or SO_2) emission rate in lb/mmBtu, or (3) using the diluent cap for calculating NO_X (or SO_2) emission rate in lb/mmBtu, heat input rate, and CO_2 emissions. In addition, EPA is proposing to add a minor additional reporting requirement to indicate whether the diluent cap is used in calculating CO_2 and heat input in the electronic data reporting format. This would allow EPA to verify facilities' calculations, while requiring less reprogramming than changing the calculations for heat input and CO_2 emissions.

The Agency solicits comment on the proposed revisions relating to the diluent cap.

4. Complex Stacks—General Issues

Background

Many power plants regulated under part 75 have relatively simple stack and monitoring configurations. Many utilities have one stack for each affected unit and have CEMS installed on the stack. Other plants have more than one unit discharging to the atmosphere through a common stack, with CEMS installed on the common stack. Still others have individual units that exhaust into multiple stacks and have CEMS installed on each stack. The monitoring requirements for these various configurations are addressed in §§ 75.13, 75.16, 75.17, and 75.18. EPA has issued guidance to assist utilities in preparing quarterly reports for these unit and stack configurations (see Docket A–97–35, Items II–I–4 and II–I–9, Policy Manual, Section 17).

For the configurations described above, the process of accounting for emissions and heat input from the units and stacks will follow simple mathematical rules. For example, for single unit-single stack configurations, the emissions and heat input for the unit are directly determined from the stack CEMS (or from an excepted methodology, where applicable). For units discharging through a common stack with CEMS on the common stack, the combined emissions and heat input are determined from the CEMS, and the heat input to each individual unit is determined by apportionment of the combined heat input, using a ratio of the unit load to the combined load of all units utilizing the common stack. For a single unit exhausting through multiple stacks, the sum of the SO_2 and CO_2 mass emissions and heat input for the different stacks equals the total SO_2 and CO_2 mass emissions and heat input for the unit.

However, in implementing part 75, EPA has become aware of a number of affected units that have stack exhaust configurations which are more complex than the configurations described above. For example, one utility has a configuration in which two units can emit through two different stacks at the same time, combining their emissions in both stacks (see Docket A–97–35, Items, II–C–1, II–D–12). In this case, the stack configuration is both a common stack and a multiple stack configuration. EPA has had significant problems in determining the emissions and heat input from these units, and in one case, EPA rejected the quarterly reports for the units (see Docket A–97–35, Item II–C–8). The utility worked closely with EPA to resolve the reporting issues resulting from this unusual situation (see Docket A–97–35, Item II–D–21). Other utilities with similar situations have contacted the Agency to ensure there would not be problems with their reporting (see, e.g. Docket A–97–35, Item II–D–5).

There have been other cases in which a unit that is accountable for holding SO_2 allowances shares a common stack with a unit that does not hold SO_2 allowances (e.g., where an affected unit and a non-affected unit share a common stack or, prior to 1/1/2000, where a Phase I unit and a Phase II unit share a common stack). These are termed ''subtractive stack'' situations in the following discussion. Utilities with subtractive stack situations have generally used the provisions of § 75.16(a)(2)(ii)(C) or § 75.16(b)(2)(ii)(B). These provisions allow a facility to monitor separately the common stack and the unit with no allowance requirement and to subtract the emissions from the non-affected or Phase II unit from the common stack emissions. In some cases, it has not been clear in the electronic quarterly reports whether a utility is reporting combined emissions from all of the units using the common stack or whether the emissions from the non-affected unit(s) have already been subtracted out of the reported emissions (see Docket A–97–35, Item II–C–18). This confusion in interpreting the quarterly emissions reports has made compliance determination difficult.

The Agency found that there is a potential problem with the underestimation of emissions using this subtractive approach. In some cases, the error in the monitors' measurements might be such that a larger emissions value is subtracted from a smaller value, resulting in the reporting of false negative emissions (see Docket A–97–35, Item A–94–16–IV–D–18, Comments from Monitor Labs). In other cases, there may be an incentive for making inaccurate measurements with the monitoring systems installed on a unit with no allowance requirement. For

example, if the SO_2 pollutant concentration monitor on a unit with no allowance requirement did not operate properly and had a significant amount of missing data, the facility would calculate SO_2 emissions from the unit using a conservative, high concentration value. Therefore, emissions reported for the units with allowance requirements would, as a result of the subtraction, be less than the actual emissions. Thus, a facility might have a disincentive for good monitor performance and accuracy, because it could lower the emissions reported for the units with allowance requirements. Though allowed under the current wording of Appendix A to part 75 and subpart D of part 75, this is contrary to the intent of the missing data substitution procedures, which is to encourage good monitor performance while preventing any systematic underestimation of emissions. (See Docket A–97–35, Items II–B–13, II–E–4, and II–I–12.)

Discussion of Proposed Changes

Today's proposed rulemaking would add a general regulatory requirement to §§ 75.16 and 75.17 for facilities with complex stack configurations (i.e., subtractive stack situations or configurations involving combinations of common stacks and multiple stacks) to receive approval from EPA's Administrator for a method of calculating and reporting emissions from the units and stacks in the configuration. The facility would be required to reach agreement with the Agency on issues such as: identification of the stack in its quarterly report, representation of the configuration in its monitoring plan, groups of units for which cumulative emissions must be reported, testing procedures, use of the bias test, and use of the missing data substitution procedures. This would apply both to sources that already have certified monitoring equipment and are submitting quarterly reports and to units that do not yet have certified monitoring systems (e.g. new units).

Rationale

The Agency evaluated two basic approaches to resolving issues in these complex stack monitoring configurations. First, EPA considered resolving the issues through policy guidance and through instructions for submitting quarterly reports. Second, the Agency considered putting detailed instructions in part 75 for reporting from and testing of monitoring systems installed in these complex stack configurations. These rule provisions would have explicitly addressed missing data substitution to ensure that when emissions are reported, they are not underestimated from units with an allowance requirement or a NO_X emission limitation. For example, EPA could have required, for the subtracted unit(s), that the facility only use those provisions of the standard missing data procedures that are not intended to be conservative estimates, such as the average SO_2 concentration during the hour before and the hour after a missing data period. Another approach for missing data substitution could have been to count zero emissions for the unit with no allowance requirement during any missing data periods. Or perhaps creation of a site-specific missing data procedure could have been required (see Docket A–97–35, Items II–E–4 and II–I–12). To prevent a potential underestimation of emissions and a disincentive for more accurate monitoring due to application of a bias adjustment on a monitor on a unit with no allowance requirement where its emissions are subtracted from a common stack, EPA could have required that the bias calculation be based upon both the monitors on the common stack and the monitors on units with no allowance requirement, resulting in a single bias adjustment factor for the subtractive stack situation.

However, EPA's experience thus far in implementing the program indicates that each complex monitoring configuration tends to be unique. Thus, the Agency has rejected the two approaches discussed above and has decided instead to make General regulatory revisions that allow for case-by-case resolution of issues in individual plant situations, rather than making extensive, detailed revisions to part 75 to address each unique situation.

The Agency prefers to make regulatory revisions rather than addressing issues solely through policy and guidance. In some cases, the Agency has given advice to utilities on how to report emissions, and the utility involved has not followed the Agency guidance (see Docket A–97–35, Items II–C–7, II–C–24, and II–D–8). In another case, the current provisions of part 75 for missing data substitution and for the bias test appeared to be in conflict with guidance that the Agency wanted to issue in order to ensure that emissions are not underestimated in a subtractive stack situation (see Docket A–97–35, Item II–B–13). Therefore, today's proposed rule would require owners or operators of facilities with complex stack configurations to apply for approval of their monitoring plans and reporting methodologies from EPA's Administrator on a case-by-case basis. The Agency believes that the General regulatory provisions requiring approval of a complex monitoring situation by EPA's Administrator will give both facilities and the Agency flexibility to deal with site-specific cases, while also giving the Agency regulatory authority to resolve any case-specific problems.

It is possible that any final rule resulting from today's proposal may not be promulgated until 1999. Thus, EPA is proposing to require the Administrator's approval of the monitoring plans and reporting methodologies only for those situations that will exist on and after January 1, 2000. Any subtractive stack situations that exist only during the duration of Phase I would not fall under this requirement. However, complex stack situations that exist where affected and non-affected units share a common stack would need to meet today's proposed requirement. Similarly, in situations where coal-fired units sharing a common stack have different NO_X emission limitations under part 76, or situations where some units sharing a common stack have a NO_X emission limitation under part 76 and others have no NO_X emission limitations under part 76, any complex monitoring configuration would need to be approved by EPA's Administrator.

5. Complex Stacks—Heat Input at Common Stacks

Background

For a unit that utilizes a flow monitor to determine SO_2 mass emissions, section 5 of Appendix F to part 75 requires heat input to be calculated using the installed flow monitor and a diluent gas (O_2 or CO_2) monitor. The January 11, 1993 final rule indicated that units with common stacks, multiple stacks, or bypass stacks should follow the same General procedures for monitoring heat input as are used for monitoring SO_2 under § 75.16. As written, those procedures allowed facilities to monitor their heat input either by placing individual monitors on each unit that serves a common stack or by placing monitors only on the common stack and measuring a combined heat input from all of the units sharing the common stack. The May 17, 1995 rule required the combined heat input measured by monitors on the common stack to be apportioned to the individual units, in two specific provisions. First, unit level heat input was required under § 75.16(e)(2) for cases in which a knowledge of the heat input for each unit is critical to compliance determination (i.e., for situations where any units using the common stack have

a NO_X emission limit). Second, § 75.16(e)(3) required unit level heat input to be determined for all other common stacks, but only until the year 2000. The November 20, 1996 rule outlined the acceptable methodology for apportioning heat input, i.e., by using the ratio of the unit load in MWe or lb of steam per hour to the combined load of all units utilizing the common stack (provided that all of the units utilizing the common stack are combusting fuel with the same F-factor).

Discussion of Proposed Changes

Today's proposed rule would revise the existing requirements found in § 75.54(b) and two specific provisions of § 75.16(e) for accounting of heat input for units serving a common stack, a by-pass stack, or multiple stacks. First, EPA would require determination and reporting of the unit level heat input to be continued after the year 2000 for all affected units, rather than restricting it to certain situations after 2000. Second, EPA would clarify that the proper units of measure for load to be used in an apportionment of common stack heat input to determine unit level heat input are totals of MWe-hr and 1000 lb of steam, rather than rates of MWe and 1000 lb/hr of steam.

Rationale

EPA considered leaving the current provisions of § 75.16(e) and § 75.54(b) from the May 17, 1995 and November 20, 1996 rules unchanged. However, this would have the serious drawback of requiring the facilities to reprogram their computer software for certain units and not for others. Corresponding monitoring plan changes would also be required. Additionally, EPA would have to reprogram its emission tracking software to accommodate two different heat input reporting methodologies for common stacks. In view of these considerations, EPA is proposing to continue to receive individual heat input data from all affected units. This information is useful for developing inventories of total NO_X mass emissions in tons in support of other Agency rulemakings. Without such information, the inventories would be based on assumptions about how units operate, rather than being based on unit level heat input as reported from the facility.

The Agency believes that a relatively small number of sources would be affected by this proposed change. This is because (1) most coal-fired units would still need to report unit level heat input under the current provisions of § 75.16(e)(2), even after the year 2000; and (2) gas-fired and oil-fired units using fuel flowmeters to determine heat input and to implement the procedures of Appendix D or Appendix E would still be required to monitor heat input for each unit under section 2.1 of Appendix D. Because of the usefulness of having heat input data for individual units, because of the burden of reprogramming software to remove the heat input apportionment by the year 2000, and because of the small number of sources that would benefit from retaining the current provisions of § 75.16(e)(3), EPA believes it is reasonable to require all units that measure combined heat input at a common stack to continue to apportion heat input to the individual units. The Agency solicits comment on the number of sources that would be affected by this revision.

6. Start-Up Reporting—Units Shutdown Over the Compliance Deadline

Background

As currently written, part 75 requires that units which are shutdown over an applicable compliance date specified in § 75.4 must submit a notice of the planned and (if different) actual shutdown date. In addition, § 75.4(d) provides an extended certification deadline for such units of ''the earlier of 45 unit operating days or 180 calendar days after the date that the unit recommences commercial operation of the affected unit.'' If an owner or operator subsequently recommences commercial operation of the unit, a notice related to the planned and (if different) actual date of recommencement of commercial operation is required. In addition to these notices, § 75.64 requires that after the applicable compliance date passes, the owner or operator must submit quarterly reports for such units. If the unit remains shut down and does not operate during the quarter, the quarterly report must show zero emissions. Utility commenters (see, e.g., Docket A–97–35, Items II–D–20, II–D–30) have recommended that this quarterly report requirement for shutdown units be deleted because it is unnecessary and burdensome.

Discussion of Proposed Changes

Section 75.64(a) would be modified so that quarterly reporting is not required until the first quarter in which a previously shutdown unit recommences commercial operation. In this case, the first quarterly report would contain data beginning with the hour in which the unit recommences commercial operation.

Rationale

Units that are shutdown over their applicable certification deadlines are required to submit notice, pursuant to § 75.61(a)(3), of the planned date of recommencement of commercial operation and also must submit a follow-up notice if the actual date of recommencement of commercial operation is different from the planned date. As a result of these notice provisions, EPA will know whenever the status of a shutdown unit changes. Because shutdown units have no emissions, the Agency believes that quarterly reporting in addition to the notice provisions is unnecessary to fulfill the emission reporting objectives of the Act.

The Agency notes, however, that the proposed revision differs from that suggested by certain utilities (see Docket A–97–35, Item II–D–30). The utilities proposed tying the reporting requirement to the certification deadline in § 75.4(d). However, under § 75.4(d), facilities are required to report emissions data using special provisions in that section prior to the extended certification deadline in § 75.4(d). Thus, the proposed revisions would tie the obligation for quarterly reporting to the quarter in which commercial operation is recommenced.

7. Start-Up Reporting—New Units

Background

As currently written, § 75.64(a) requires the first quarterly report for new units to be submitted for the quarter corresponding to the compliance date in § 75.4. However, the current provision is unclear about which hourly emissions data need to be included in the first quarterly report if the compliance deadline does not correspond to the first hour in the quarter.

Discussion of Proposed Changes

Section 75.64(a) would be modified to clarify that a new unit must start reporting data beginning with the earlier of the date and time of provisional certification or the compliance deadline in § 75.4(b).

Rationale

These proposed revisions are generally consistent with existing implementation of the new unit reporting requirements, and primarily would serve to clarify ambiguous elements of the current rule.

8. Recordkeeping and Reporting Provisions

Background

Subpart F and subpart G of the existing part 75 regulation set forth the recordkeeping and reporting requirements that accompany the monitoring provisions of part 75. Specifically, in subpart F, § 75.53 contains the monitoring plan requirements, § 75.54 contains the general recordkeeping provisions, § 75.55 lists the general recordkeeping provisions for specific situations, and § 75.56 consists of the certification, quality assurance and quality control record provisions. In subpart G, § 75.62 lists the monitoring plan reporting provisions, § 75.62 contains the reporting requirements for initial certification and recertification applications, and § 75.64 discusses the provisions for quarterly reports. Quarterly reports are electronic data files containing emissions and operating data from affected units, as well as monitoring plan information and the results of certification and quality assurance tests. Under § 75.64, these electronic data reports are required to be submitted to the Agency each calendar quarter. This electronic information is used by the Agency for many different purposes, including implementation of the SO_2 allowance trading program, determination of compliance with emission limits, development of reports on utility emissions, and modeling of air quality to assess the effectiveness of the Act.

In order to effectively use the electronic quarterly report information, EPA created a standardized reporting format, the electronic data reporting (EDR) format. The electronic file formats and record structures of the EDR provide the vehicle by which required information is submitted to the Agency every calendar quarter. The EDR primarily defines the order, length, and placement of information within the electronic report or file. The individual tables of the EDR define the record type, type code, start column, data element description, units, range, length, and FORTRAN format for each data element in the electronic report. The information in the EDR fields mirrors the required information set forth in subparts F and G of part 75. Considering both the volume of information contained in each quarterly report (e.g, operating and emissions data for each of the hours in the quarter) and the number of reports submitted to the Agency (i.e., currently, 1765 reports are received each quarter for the 2055 affected units; some reports contain information for more than one unit if several units are interrelated, as in a common stack configuration), a standard format is critical in order for the Agency to review, verify, and use the information reported. A standard format allows the Agency to develop software to receive and verify the files and to correlate and separate out specific information for compliance determinations. A standard format also allows software vendors to create standard software which can be utilized by many affected units. This is more cost effective than developing site-specific software and thus reduces the software cost to industry.

Today's rulemaking proposes a number of revisions to subparts F and G of part 75 (the reporting and recordkeeping sections of the rule). The majority of these changes are necessary to implement the proposed substantive revisions to the sections of the rule and appendices discussed elsewhere in this notice. In addition, EPA is proposingrevisions to these subparts in order to streamline implementation of the program and to coordinate reporting under the Acid Rain Program with other programs.

To support the changes to the recordkeeping provisions, new §§ 75.57, 75.58, and 75.59 would be added. These sections would replace existing §§ 75.54, 75.55, and 75.56. The addition of new sections is necessary because the proposed revisions would not be mandatory until January 1, 2000, and to have the proposed revisions listed throughout existing effective sections could lead to confusion. However, an owner or operator would be free to follow the provisions of §§ 75.57, 75.58, and 75.59 before January 1, 2000, if he chooses to do so. In addition, the owner or operator would be required to satisfy, prior to January 1, 2000, the elements in these sections that support a regulatory option proposed in other sections of part 75 if the owner or operator elects to implement that option prior to January 1, 2000.

Because, as discussed above, the Acid Rain Program relies on a standardized electronic data reporting format, EPA has also developed draft revisions to the EDR formats and instructions (draft EDR version 2.1). The following discussion refers to both the rule sections and EDR record types (RTs) that would be affected by the proposed revisions.

Discussion of Proposed Changes

There are a number of proposed rule changes to the recordkeeping and reporting requirements of part 75 and corresponding draft EDR revisions that would be necessary to implement the substantive revisions proposed by EPA and discussed elsewhere in this preamble. These include the following requirements:

(1) Changes to support new CO_2 missing data requirements (see § 75.57 and RT 202, 210, and 211);

(2) Changes to support new reporting, QA and missing data requirements for moisture monitoring (see §§ 75.53, 75.57, and 75.59, and RT 211, 212, 220, and 618);

(3) Changes to support optional Appendix I (flow methodology for gas and oil units) (see §§ 75.57 and 75.58, and RT 220, 302, 303, 608, and 609);

(4) Changes to support more flexibility for units that have multiple range analyzers (see §§ 75.53 and 75.59, and RT 230, 530, 600, 601, and 602);

(5) Changes to support the use of the diluent cap during all hours (see § 75.57 and RT 300 and 330);

(6) Changes to support test exemptions and extensions for units that operate infrequently (see §§ 75.59 and 75.64, and RT 301, 697, and 698);

(7) Changes to support increased flexibility in fuel sampling (see § 75.58 and RT 302, 303, 313, and 314);

(8) Changes to allow reporting of hourly total values in addition to hourly rates (see § 75.57 and RT 300, 310, and 330);

(9) Changes to support the proposed re-definition of unit operating loads (see §§ 75.53 and 75.59, and RT 535 and 611);

(10) Changes to support reporting of conditional data during recertification events (see § 75.59, and RT 556);

(11) Changes to support a new quarterly flow-to-load QA check for flow monitors (see § 75.59, and RT 605 and 606);

(12) Changes to allow QA test grace periods (see § 75.59, and RT 699);

(13) Changes to support simplified reporting for low mass emissions units (see §§ 75.53, 75.58, and 75.63, and RT 360, 508, and 531);

(14) Changes to support fuel flow-to-load QA checks for fuel flow meters (see § 75.59, and RT 628 and 629); and

(15) Changes to support expanded reporting of RATA supporting information (see § 75.59, and RT 614, 615, 616, 617, and 618).

In addition, since the EDR version 1.3 was released, EPA has developed additional record types to aid in the implementation of the program, by allowing the designated representative to certify the validity of quarterly reports using an electronic certification statement. The proposed revisions would adopt the necessary rule language to implement these miscellaneous record types (see § 75.64, and RT 900, 901, 910, and 920).

The proposed revisions would also set forth optional requirements for reporting of NO_X mass emissions that states or EPA could adopt as part of a NO_X mass trading program, such as the OTC NO_X Budget Program. In this situation both a rule change and an EDR change would be needed (see §§ 75.57 and 75.64 and RT 301, 307, and 328).

The proposed rule revisions also include a number of changes that EPA believes will facilitate implementation of the program. These include:

(1) Reporting of test numbers, reasons for tests and indicators of aborted tests (see § 75.59, and RT 560, 600, 601, 602, 603, 610, and 611);

(2) Changing the deadlines for reporting the RATA supporting information that was originally required on January 1, 1998 (see § 75.59, and RT 614, 615, 616, 617, and 618);

(3) Reporting of an optional record type that will allow facilities to provide contact person information that many facilities currently provide in quarterly report cover letters (see § 75.59, and RT 999);

(4) Based on comments received, the rule would be revised so that reporting the reasons for missing data as part of the quarterly report would become optional, but would still need to be maintained on-site (see §§ 75.56 and 75.59, and RT 550);

(5) Reporting of facility location, identification, and EDR version numbers to support the transition from EDR 1.3 to EDR 2.1 (see § 75.64, and RT 100 and 102);

(6) Reporting of information documenting the calculation of heat input (see § 75.57, and RT 300);

(7) Reporting of reference method backup QA data (see § 75.59(a)(11), and RTs 260, 261, and 262);

(8) Expanded reporting of unit definition information (see §§ 75.53, and RTs 504, 585, 586, and 587);

(9) Reporting of Appendix E segment ID information (see § 75.58, and RT 323, 324, and 560);

(10) Reporting of qualification data for peaking units or gas-fired units (see § 75.53, and RT 507);

(11) Reporting of the qualifying test for off-line calibrations (see § 75.59, and RT 623);

(12) Reporting of Appendix E emission rate test data (see §§ 75.59, and RT 650–653);

(13) Reporting of span effective date information and flow rate span values (see § 75.53, and RT 530); and

(14) Removal of the recordkeeping provisions of §§ 75.50, 75.51, and 75.52 that are no longer effective.

Rationale

The majority of the proposed changes to subparts F and G are needed to support proposed substantive changes elsewhere in part 75. EPA is also proposing certain minor revisions to the order and wording of provisions in these subparts so that the records required by the rule match up consistently with the record type descriptions in the EDR. Certain utility groups previously had objected that EPA had not made the EDR format available for formal public notice and comment. The Agency maintains that it is not required to provide notice and comment for the EDR. The data included in (or proposed to be included in) the EDR are also listed in the rule (or the proposed rule revisions) as requirements under the recordkeeping and/or reporting provisions of §§ 75.53 through 75.64, which have already undergone (or are undergoing) public notice and comment. Since the EDR simply shows how to present electronically the data whose submission is (or will be) required by the rule, it is the rule, not the EDR, that imposes the data requirements. Notice and comment on the contents of the EDR would therefore be unnecessary and duplicative. Moreover, the requirement to present the rule's data requirements in a specified format is authorized by § 75.64(d), which requires a quarterly report to be submitted in the format specified by the Administrator. Like the data requirements, this format requirement in part 75 was adopted after public notice and comment.

In today's rulemaking, EPA has developed draft EDR revisions simultaneously with the proposed rule revisions and is therefore including the draft EDR revisions in the docket for comment at the same time as the proposed rule revisions (see Docket A–97–35, Item II-A–12). EPA is also posting the draft EDR v2.1 revisions and draft EDR v2.1 reporting instructions on the Acid Rain Homepage (www.epa.gov/acidrain). However, the Agency maintains that notice and comment are not necessary for revisions to the EDR so long as the data included in the EDR is the same as the data required by rule provisions that have undergone or are undergoing notice and comment. Thus, future EDR revisions may be made without prior notice and comment on the EDR in order to implement rule revisions for which notice and opportunity for comment are provided. However, the Agency will continue its informal procedures for involving the affected stakeholders in any such EDR revisions.

There are a number of other proposed changes to §§ 75.54–75.64 that have been included to implement existing provisions in other sections of part 75. First, information on test numbers and reasons for tests would be required so that quality-assurance test data can be more easily correlated and interpreted. Second, the reporting of various run-specific and point-specific RATA support information would be required (e.g., point velocity head readings, gas reference method quality-assurance data, moisture reference method data, etc.). The Agency believes that most testing companies currently either collect these data electronically or enter the data into computer programs manually to determine RATA results. By requiring the reporting of these data elements in a standard electronic format, the Agency believes that both facilities and regulatory personnel would be able to more easily interpret data that are currently provided by test contractors in many different hardcopy formats.

The Agency is proposing not to require the electronic reporting of RATA support information prior to the year 2000. Sections 75.56 (a)(5)(iii)(F) and (a)(7) and § 75.64(a)(1) of part 75 currently require RATA supporting information to be reported in the electronic quarterly report. EPA believes, however, that it would be more cost effective to require the more detailed RATA support records to be electronically reported beginning in the year 2000, rather than having a two-stage implementation. The Agency has notified all designated representatives that this RATA supporting information will not be required to be reported electronically, in RT612 and 613 of the quarterly report, prior to January 1, 2000.

The Agency notes that certain data elements (e.g., yaw angle, pitch angle, axial velocity, wall effect point identifier, etc.) have been included in anticipation of future revisions to EPA Reference Method 2. EPA is presently evaluating a number of alternative flow rate measurement methodologies, such as the use of a 3-dimensional probe. Depending on the outcome of the Agency's evaluation, one or more of these alternative flow measurement techniques may be allowed beginning in the year 2000. Therefore, EPA believes it is appropriate to include data elements to support these anticipated Method 2 revisions in draft EDR version 2.1.

Finally, by changing the requirements for reporting the results of the most recent RATA from requiring it to be reported in the quarter in which it was

performed, to requiring it to be reported in the quarter in which it was performed and each subsequent quarter in which a BAF that was calculated using the results of that RATA are used, EPA would make the individual quarterly reports more self contained and make it easier for people who are using the reported data to understand how the BAFs reported in those reports were applied. EPA considered adding a field to the hourly emissions data record for each pollutant to indicate the BAF applied in that hour. However, the Agency received requests from utilities on an early draft of the EDR revisions that the hourly emissions data record types not be revised to add a field for BAF. The Agency believes that reporting the results of the most recent RATA, including the BAF, in each quarterly report would accommodate the utilities' requests not to add the BAF to each hourly record type and would achieve the objective of making the quarterly reports easier to interpret because the BAF being applied will be found in each quarterly report. In addition, since electronic RATA results involve a relatively small amount of information that can be copied into subsequent reports and does not have to be recreated, it should not be a significant burden to reporting facilities.

The proposed revisions would also remove the requirement to report the reasons for missing data and make it optional. However, even if the information is not reported, the reasons for missing data would have to be maintained on site in a manner suitable for inspection. Based on the high data availability achieved during initial implementation of the program, the Agency believes that this type of information is not needed in the review of most quarterly reports. For those situations in which the Agency may wish to review this information, the records would still be on-site for audit purposes or for submittal to the Agency.

The EPA is also proposing to incorporate additions which would allow the reporting of electronic signatures and certification statements so that no hardcopy reporting of any kind (e.g., cover letters) would be necessary to meet the quarterly report requirements.

Finally, the removal of recordkeeping §§ 75.50, 75.51, and 75.52 (and the corresponding explanatory text included in Appendix J to the existing rule) is necessary because those sections were scheduled for replacement during the May 17, 1995 rule revisions. At that time, §§ 75.54, 75.55, and 75.56 were added as replacements for §§ 75.50, 75.51, and 75.52, effective January 1, 1996. Because the effective date is now past, the old sections and Appendix J will be removed and reserved in order to prevent any confusion.

9. Electronic Transfer of Quarterly Reports

Background

Sections 75.64(a) and (d) of the original January 11, 1993 Acid Rain rule requires emissions, monitoring, and quality assurance data to be electronically reported to the Administrator on a quarterly basis in a format to be specified by the Administrator. Version 1.3 of the Electronic Data Reporting (EDR) format (see Docket A–97–35, Item II–I–5) further specifies the record structures to be used to report the required data elements. Page 3–3 of the May 1995 Acid Rain Program CEMS Submission Instructions (see Docket A–97–35, Item II–I–4) further specifies the mode of transmission of the electronic data file to the Agency. Three modes of transfer are listed as options: (a) by mail on diskette, (b) by mail on magnetic tape, or (c) through direct electronic transfer.

Since the beginning of the program, the Agency has received quarterly reports by mail on diskette and through direct electronic transfer. To date, the magnetic tape option has never been utilized. Based on the first four years of implementation of part 75, the Agency believes that the use of the direct electronic transfer mode of transmission has many advantages to the Agency and to the affected sources. In fact, more than seventy percent of the reports for sources currently affected by part 75 were submitted directly to the EPA mainframe with EPA-provided software in second quarter 1997, and the number of sources using this option has steadily increased over time (see Docket A–97–35, Item II–I–8).

Discussion of Proposed Changes

Today's proposal would require quarterly reports to be submitted via direct electronic transfer unless otherwise approved by the Administrator. This would remove the option of sending files through the mail on interceding media except for hardship cases where a modem is not available or where technical difficulties prevent the successful transmission of files via modem.

An additional revision to section 4 of Appendix A to part 75 would require data acquisition and handling systems (DAHS) to be capable of transmitting a record of measurements and other required information by direct computer-to-computer electronic transfer via modem and EPA-provided software.

Rationale

For each quarterly report submitted, the Agency performs an assessment which results in a feedback report for the submitting designated representative. This feedback report provides information to the facility that may be used in making trading decisions, that may indicate that a change is needed to the facility software, and/or that may indicate that the file needs to be corrected and resubmitted. A major advantage of submission through direct electronic transfer with a modem and EPA-provided software is that the designated representative submitting the file receives the EPA assessment of the submitted data much more quickly than for a file that is transmitted through the mail on diskette. Currently, for a file that is submitted to the Agency by electronic transfer via modem and EPA-provided software, the EPA assessment is received by the designated representative, via modem and EPA-provided software, immediately (typically within ten minutes) after the transmission of the quarterly report file. However, for files submitted on diskette that must travel through the mail system and be processed by Agency personnel, a letter containing the EPA assessment is currently sent to the designated representative through the mail and arrives 45 days or later from when the submission was originally received by the Agency. Therefore, with direct electronic transfer, potential errors get corrected and resolved more quickly and trading decisions can be made with assurance that submitted data meets the minimum quality standards acceptable to the Agency. Additionally, the source may electronically submit the quarterly report, via modem and EPA software, prior to the deadline, immediately receive the EPA assessment, fix any errors, and resubmit the file by the deadline. Many utilities have indicated that this is an important advantage over submission of the quarterly report by diskette.

Another benefit of direct electronic transfer is the reduced risk of error in transmission to the Agency or handling at the Agency. Throughout the implementation of the program, many files submitted on diskette through the mail have been lost, returned to the sender, damaged in transit, or contained viruses (see Docket A–97–35, Item II–I–8). When a file is submitted using direct electronic transfer of a quarterly report, the designated representative submitting the file(s) receives an immediate

confirmation that the file was received by the Agency.

Further, immediate feedback from the agency on quarterly report submissions may also contribute to cost savings for facilities if a file submitted via direct electronic transfer is rejected and required to be amended and resubmitted. Utilities have indicated that submitting the report to EPA, receiving feedback, and making the necessary corrections to the file in a single work session significantly reduces the cost of reworks, particularly for facilities that retain their master file at the individual plant locations.

An additional advantage to direct electronic transfer is the reduced cost to the Agency resulting from the minimized EPA labor hours required to process a diskette. For instance, a diskette transmitted through the mail must be catalogued, scanned for readability and viruses, uploaded to the EPA mainframe Emissions Tracking System, and renamed. On the other hand, transmission of a file by direct computer-to-computer electronic transfer using EPA software eliminates all of those manual steps because they are performed automatically by the EPA software used for transmission of the report.

A possible concern about a requirement to submit the quarterly report via modem is the possibility that source may not be equipped with a modem and electronic transfer capability. Although the Agency believes that most sources currently have a modem or will have a modem by the year 2000, the Agency understands that a very small percentage might not. Therefore, the Agency would accept petitions from sources unable to transmit files via modem in order to allow transmission via diskette for hardship cases.

Additionally, a utility group representative raised a concern about the possibility of a computer at either the facility source or at the EPA being inoperative at the time of the deadline for transmission, preventing a source from successfully transferring the quarterly report to the Agency. In order to minimize the risk of this type of problem, there is a wide window, currently thirty days, during which EPA will accept quarterly report transmissions each quarter. Additionally, EPA has instituted preventative measures to minimize the possibility that the EPA computer would be inoperative for an extended length of time, preventing quarterly report transmission. Nevertheless, the Agency accepts that it is conceivable that a technical difficulty could prevent the successful electronic submission of a quarterly report and, therefore, would also approve diskette submission on an as-needed basis for sources unable to transfer a file via modem and EPA-provided software due to technical difficulties. Furthermore, EPA solicits comment on whether it should allow a grace period for late submissions due to a technical difficulty with the EPA computer.

Finally, section 4 of Appendix A to part 75 would be amended to require the DAHS to be capable of transmitting the required information by direct electronic transfer via modem and EPA-provided software, for consistency with the proposed § 75.64(f). In addition, section 4 of Appendix A to part 75 would retain the requirement for the DAHS to be capable of transmitting a record of measurements and other required information via an IBM-compatible personal computer diskette so that an on-site inspector could collect electronic data on a diskette for review.

S. Revised Traceability Protocol for Calibration Gases

Background

Currently, Appendix H to part 75 requires affected units to follow a 1987 version of EPA Protocol procedures for developing calibration gases. This protocol document has been superseded by a later version, the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA 600/R–97/121. The 1997 document is actually five protocols. Two of these protocols (formerly known as Protocols 1 and 2) have been combined to allow both CEMS and ambient air analyzers to be calibrated from gases produced either without dilution (Procedure G1) or with dilution (Procedure G2). The remaining three protocols (Procedures P1, P2, and P3) describe procedures that are mandatory for ambient air quality analyzers (not continuous emission monitoring systems).

The 1997 Protocol document, described above, is required by other parts of the CFR, such as the NSPS provisions in part 60. Because the old and new protocols specify different certification periods (i.e., useful shelf lives) for most calibration gases, some affected units that must comply with both part 60 and part 75 have been forced to replace calibration gas cylinders more frequently because of the shorter certification period in the 1987 Protocol procedures required by part 75.

Under the 1987 Protocol document, affected units with low SO_2 emission rates occasionally had difficulty finding calibration gases that were within the concentration ranges required by Appendix A to part 75. The 1997 Protocol document allows calibration gases to be developed over a wider range of concentrations than was previously allowed.

Under the current part 75 rule, ''Protocol 1 gases must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value).'' However, no method is specified to determine the uncertainty value. The overall uncertainty in the concentration estimated for a calibration gas comes from many different sources, including uncertainty in the reference standards, uncertainty in the analyzer multi-point calibration, uncertainty in the zero/span correction factors, and measurement imprecision.

Discussion of Proposed Changes and Rationale

Today's rule proposes to remove Appendix H and revise parts 72 and 75 to be consistent with the 1997 Protocol document. The following sections of part 75 would be revised: §§ 72.2 and 72.3; sections 5.1.1 through 5.1.6, 6.2, and 6.3.1 of Appendix A; and all of Appendix H.

The final rule would incorporate by reference the 1997 Protocol document. This is the preferred option for the following reasons: (a) calibration gas certification periods would be identical under parts 60 and 75, thereby allowing affected units to reduce expenditures on calibration gas without sacrificing accuracy or performance; (b) lower emitting affected units would more easily be able to comply with the required range of calibration gas concentrations; (c) improved assaying procedures and accuracy determinations would be allowed; and (d) a wider selection of calibration gases would be allowed.

While today's proposal would retain the requirement for EPA protocol gases to be within 2.0 percent of the tag value, section 5.1.3 in Appendix A would be revised to specify the use of the uncertainty calculation procedure in section 2.1.8 of the 1997 Protocol document for estimating the analytical uncertainty associated with the assay of the calibration gas. This uncertainty estimate includes the uncertainty of the reference standard and any gas manufacturer's intermediate standard (GMIS) and interference correction equation that may be used in developing the calibration gas.

EPA proposes to change the term ''Protocol 1 gas'' to ''EPA protocol gas'' because the 1997 Protocol document combines the Protocol 1 and Protocol 2

procedures; therefore, the term ''Protocol 1 gas'' would no longer be used.

Today's proposal would also continue to allow a ''research gas mixture'' to be used as a calibration gas. However, an RGM would need to meet the same 2.0 percent uncertainty requirement that a protocol gas would meet.

The proposed rule would explicitly allow GMISs to be used as calibration gas for two reasons. First, an EPA protocol gas may be made from a GMIS. Therefore, GMISs are at least as accurate as EPA protocol gases. Second, GMISs are more readily available and less expensive than standard reference material or National Institute of Standards and Technology (NIST) traceable reference material, both of which are allowable as calibration gas under part 75.

Today's proposal clarifies that NIST/EPA-approved certified reference materials (CRMs) would be acceptable as calibration gas by adding those CRMs to the definition of ''calibration gas'' in § 72.2.

The 1997 Protocol document accepts primary reference standards from the Netherlands Measurement Institute as being equivalent to standard reference materials from the NIST. As a result, today's proposal adds ''standard reference material-equivalent compressed gas primary reference material'' to the ''calibration gas'' definition in § 72.2 and to section 5.1.2 of Appendix A.

Finally, the definition of ''zero air material'' would be revised to accommodate other acceptable procedures.

Major differences between the 1987 Protocol procedures and the 1997 Protocol procedures are explained on pages 1–1 through 1–3 of the 1993 Protocol document and on pages 1–1 through 1–2 of the 1997 Protocol document (see Docket A–97–35, Items II–I–23 and 24).

T. Appendix I—New Optional Stack Flow Monitoring Methodology

Background

Section 412 of the Act requires that units subject to title IV install SO_2 concentration monitors and volumetric flow monitors for the purpose of determining SO_2 emissions. The purpose of the volumetric flow requirement is to enable a unit to convert SO_2 concentrations into mass emission rates of pounds per hour (lbs/hr). Volumetric flow is also used to determine heat input rate in mmBtu/hr and CO_2 mass emission rate in ton/hr.

In December 1991, 56 FR 63002 (December 3, 1991), EPA proposed an exception to the requirement to install SO_2 concentration monitors and volumetric flow monitors at oil- and gas-fired units in Appendix D to part 75. The exception relies on fuel flowmeters and fuel sampling and analysis to determine SO_2 emissions from oil- and gas-fired units. In comments on the December 1991 proposed rule, some industry commenters also advocated allowing oil- and gas-fired units to use a diluent monitor, an F-factor, and a fuel flowmeter as an alternative to a volumetric flow monitor. An F-factor is a fuel-specific constant that relates the heat content of a fuel and the volume of gases given off upon combustion. It is used to convert pollutant concentrations into units of pounds of pollutant per million British thermal units of heat input (lb/mmBtu). EPA already allows the use of F-factors in emissions monitoring under part 75 and under 40 CFR part 60, subparts Da and Db. Method 19 of Appendix A to part 60 uses F-factors as the reference methods for calculating SO_2 and NO_X emissions in terms of lb/mmBtu for subpart Da and Db units. F-factors also are used in the performance tests for certain pollutants required under § 60.8 to determine if a source is in compliance with a particular emission standard in lb/mmBtu. Part 75 also uses F-factors in conjunction with diluent gas and volumetric flow data to determine heat input under section 5 of Appendix F to part 75. Table 19–1 of Method 19 in Appendix A to part 60 and Table 1 in section 3.3.5 of Appendix F to part 75 list the appropriate F-factors for different types of fuel, including oil and natural gas.

Although the commenters supported the two exceptions included in Appendix D, some commenters did not believe the exceptions would be economical at all oil- and gas-fired units. According to one commenter, fuel sampling protocols have an inherently high bias because they assume a 100 percent conversion of fuel sulfur into SO_2, which results in higher emissions reporting from fuel sampling protocols than from CEMS. The commenter claimed that the high bias appears to be in the range of 5 to 10 percent. According to the commenter, the higher emissions reporting ''penalty'' that is inherent in fuel sampling protocols would justify installing SO_2 CEMS at some oil- and gas-fired units, particularly large, base-loaded oil-fired units. In addition, the commenter claimed that, for oil- and gas-fired units which install SO_2 CEMS, use of the ''F-factor/fuel flow method''—which includes use of an F-factor, a fuel flowmeter, fuel sampling data, and a diluent (CO_2 or O2) concentration monitor—would provide much more accurate and precise information than volumetric flow monitors (see Docket A–90–51, Item IV–D–184).

In a four-day experiment performed in 1991 by one commenter, measurements from the F-factor/fuel flow method were compared to those generated by a combined SO_2 CEMS and a volumetric flow monitor. However, EPA did not believe that four consecutive days of data were sufficient to support a conclusive equivalency determination. Instead, in the January 11, 1993 final rule (58 FR 3590, 3643), EPA reserved Appendix I to part 75 for the F-factor/fuel flow method and stated that, to be approved, the method would have to meet the criteria for alternative methods as required by section 412 of the Act and the provisions of § 75.40 in a 30-day (720 hour) trial.

Section 412 of the Act requires that an alternative monitoring system provide information with ''the same precision, reliability, accessibility, and timeliness as that provided by CEMS . . .'' 42 U.S.C. 7651k. To be approved, the alternative monitoring system must meet the criteria for alternative methods in a 720 hour trial as required by the provisions of subpart E of part 75. The rule designates a certified CEMS or a reference method according to Appendix A to part 60 as the reference for evaluating the alternative monitoring system's performance.

In order to meet the precision and reliability criteria, an alternative monitoring system must achieve performance specifications and quality assurance requirements equivalent to those for CEMS. In addition, to demonstrate precision, an alternative monitoring system must pass three statistical tests evaluating the flow CEMS and alternative method in terms of their respective systematic error, random error, and correlation. Additionally, to meet the reliability criterion, the alternative monitoring system is required to match a certified CEMS in terms of annual availability. Finally, to meet the accessibility and timeliness criteria, an alternative monitoring system must match the CEMS' ability to record requisite emissions data on an hourly basis and report results within 24 hours.

In 1995, Long Island Lighting Company (LILCO) sponsored an ''alternative flow monitor demonstration project'' to demonstrate the equivalency of fuel flow measurements and F-factor calculations to stack instrument flue gas measurements for the determination of volumetric flow. The project was

performed by Entropy at LILCO's Port Jefferson Unit 4, a 180 MW oil-fired unit that burns residual oil with a maximum sulfur content of one percent. The components of the alternative method consisted of a fuel flowmeter and a CO_2 CEMS. The alternative F-factor/fuel flow method was compared to a flue gas volumetric flow CEMS.

Testing of the F-factor/fuel flow method took place in April–May 1995, and 739 hours of data were collected over a wide range of operating loads (40 MW—190 MW). Fuel oil samples were taken daily and analyzed for density and carbon content. The alternative method successfully passed statistical tests but showed statistically significant bias (see Docket A–97–35, Item II–D–14). Due to the bias uncovered during the test, EPA concluded that the alternative flow monitor demonstration project did not meet the requirements of subpart E of part 75 for an alternative monitoring system. However, EPA is proposing that a default multiplier, derived from the demonstration data, be incorporated into the equations used under Appendix I to compensate for the detected systematic bias and thereby help to ensure that emissions are not underestimated when using the F-factor/fuel flow method. With these provisions, EPA proposes to include the F-factor/fuel flow method as an excepted method for determining flow in Appendix I to part 75. The proposed default multiplier, 1.12, is based on the data and results of the LILCO demonstration and is supported by EPA and the Class of '85 Regulatory Response Group. The default multiplier would be incorporated into the equations used under Appendix I whenever a relative accuracy test audit is performed on a component-by-component basis as was proposed in the LILCO demonstration.

Discussion of Proposed Changes

EPA proposes to include the F-factor/fuel flow method in Appendix I as an excepted method for use in place of a volumetric flow monitor for oil- and gas-fired units that burn only natural gas and/or fuel oil. The F-factor/fuel flow method uses fuel flow measurement, fuel sampling data, CO_2 (or O_2) CEMS data and F-factors to determine the flow rate of the stack gas. EPA proposes limiting use of the F-factor/fuel flow method to oil- and gas-fired units that burn only natural gas and/or fuel oil because of the greater fuel consistency of oil and natural gas and because the fuel flow rates of oil and natural gas can be monitored accurately with a fuel flowmeter, unlike the feed rate of coal.

Appendix I flow monitoring would be done using any of the following combinations of components: a CO_2 monitor and a volumetric oil flowmeter, a CO_2 monitor and a mass oil flowmeter, a CO_2 monitor and a volumetric gas flowmeter, an O_2 monitor and a volumetric oil flowmeter, an O_2 monitor and a mass oil flowmeter, or an O_2 monitor and a volumetric gas flowmeter.

Today's proposal would amend § 75.20, ''Certification and Recertification Procedures,'' to add certification and recertification procedures for units using Appendix I flow monitoring systems. Initial certification of the components of the F-factor/fuel flow method would be performed either component by component or on a system basis. If each component is tested separately, then the fuel flowmeter would be tested in accordance with section 2.1.5 of Appendix D, and the CO_2 or O_2 monitor would have to pass a 7-day calibration test, a linearity check, a cycle time test and a relative accuracy test audit (RATA) using Method 3A from Appendix A to part 60. A bias test would also have to be conducted. If the excepted Appendix I flow monitoring system is tested as an entire system, then the following tests would be performed: a 7-day calibration error test, a linearity check, and a cycle time test on the CO_2 or O_2 monitor, and a relative accuracy test audit on the entire excepted flow monitoring system using Method 2 from Appendix A to part 60, and a bias test. The owner or operator would also test the data acquisition and handling system. Upon successful completion of all certification tests, the Appendix I system would be considered provisionally certified.

Today's proposal would amend § 75.21, ''Quality Assurance and Quality Control Requirements,'' to include Appendix I flow monitoring systems. A unit utilizing the optional F-factor/fuel flow method would have to meet ongoing quality assurance testing requirements. First, the daily and quarterly assessment requirements for a CO_2 or O_2 monitor in sections 2.1 and 2.2 of Appendix B would have to be followed. Second, one of the following would have to be met, depending on whether the owner or operator chooses to test the method on a component-by-component basis or on a system level: (1) the fuel flow meter quality assurance requirements and a separate RATA on the CO_2 (or O_2) monitor; or (2) a system level flow RATA. If the components are tested separately, the applicable procedures in section 2.1.6 of Appendix D would have to be followed for the fuel flowmeter quality assurance (i.e., a flow meter accuracy test, a transmitter accuracy test and primary element inspection, and/or the supplemental quarterly fuel flow-to-load quality assurance testing) and the applicable RATA procedures in sections 6.5 through 6.5.2.2 of Appendix A for the CO_2 (or O_2) monitor would be followed. In addition, the bias test would have to be performed on the CO_2 (or O_2) monitor and, if the bias test is failed, a bias adjustment factor (BAF) would have to be calculated and applied to hourly data.

If the entire system is tested, the applicable procedures in sections 6.5 through 6.5.2.2 of Appendix A would have to be used to meet the performance specifications for flow relative accuracy in section 3.3.4 of Appendix A. The bias test would have to be performed on the volumetric flow data and, if the bias test is failed, a BAF would have to be calculated using the procedures in section 7.6 of Appendix A.

Several other sections of the rule would be modified or added in order to incorporate the new excepted method described in Appendix I, including §§ 75.30, 75.57, 75.58, and 75.59. Section 75.30, ''General Provisions'' (for missing data substitution procedures), would be modified by adding quality assured data from a certified excepted flow monitoring system under Appendix I to the list of monitoring systems that measure flow rate data, for which the missing data substitution procedures of subpart D are required. If fuel sampling data, fuel flow rate data, and diluent gas data are missing, then the data acquisition and handling system would have to substitute for missing volumetric flow data. In addition, § 75.57, would include additional information that Appendix I flow monitoring systems must record. This includes fuel flow rate data and data from component monitors. Section 75.58(g) would be added to address specific volumetric flow rate record provisions for units using the optional protocol in Appendix I. Section 75.59, ''Certification, Quality Assurance and Quality Control Record Provisions,'' would also include certification and quality assurance information that facilities must record for Appendix I flow monitoring system tests.

Finally, the new proposed Appendix I would describe the applicability, procedures, calculations, missing data, and recordkeeping and reporting requirements for units using Appendix I to determine flow.

The Appendix I formulas are more complex if an O_2 monitor is used. EPA proposes to allow the use of an O_2 monitor for Appendix I; however, the

initial programming of the formulas and monitoring plan development may take longer for Appendix I flow monitoring systems that use an O_2 monitor.

Volumetric stack flow rate during oil combustion would be calculated from (1) a bias adjustment factor from the applicable bias test results; (2) the fuel flow rate (in gal/hr); (3) the fuel density (in lb/gal); (4) the percent carbon by weight; (5) the CO_2 (or O_2) concentration percent by volume; and (6) the appropriate conversion factor. The carbon content of the fuel would have to be determined according to the procedures in section 2.1 of Appendix G and the density of the oil would have to be determined according to the procedures in section 2.2 of Appendix D.

Rationale: EPA is proposing an F-factor/fuel flow method in Appendix I to part 75 as an excepted method to measure volumetric flow directly with a flow monitor because this method would allow fuel flow measurement with a gas or oil flowmeter, fuel sampling data, CO_2 (or O_2) CEMS data, and F-factors to determine the flow rate of the stack gas rather than a volumetric flow monitor. The F-factor/fuel flow method would be available for use by oil-fired and gas-fired units, as defined under § 72.2, provided that they only burn natural gas and/or fuel oil. For these units, EPA believes that the proposed method would provide acceptably accurate measurements of volumetric flow, while affording cost savings that some industry representatives estimate could be substantial. The Agency solicits comment on the proposed Appendix I and associated changes to part 75.

Appendix I may offer cost savings to some oil and gas fired units. Representatives from oil- and gas-fired units have estimated that the costs of operating, maintaining and testing volumetric flow monitors range from approximately $15,000 to $25,000 per year. In contrast, using the F-factor/fuel flow method is estimated to result in costs of only approximately $5,000 to $7,000 per year due to elimination of the operating, maintenance, testing and fuel costs associated with the volumetric flow monitor.

U. The Use of Predictive Emissions Modeling Systems (PEMS)

A number of parties have submitted preliminary field test data designed to demonstrate that EPA should set forth specific requirements for alternative monitoring methodologies that predict NO_X emission rates at gas-fired units. These ''predictive emissions modeling systems'' (PEMS) use mathematical models to predict NO_X emission rates based on sensor readings of key operating parameters. The agency is evaluating the submitted data and will consider taking further action under a future rulemaking if additional study demonstrates the equivalency of PEMS to CEMS for well defined classes of units.

IV. Administrative Requirements

A. Public Hearing

If requested as specified in the **DATES** section of this preamble, a public hearing will be held to discuss the proposed regulations. Persons wishing to make oral presentations at the public hearing should contact EPA at the address given in the **ADDRESSES** section of this preamble. If necessary, oral presentations will be limited to 15 minutes each. Any member of the public may file a written statement with EPA before, during, or within 30 days of the hearing. Written statements should be addressed to the Air Docket address given in the **ADDRESSES** section of this preamble.

A verbatim transcript of the public hearing, if held, and all written statements will be available for public inspection and copying during normal working hours at EPA's Air Docket in Washington, DC (see the **ADDRESSES** section of this preamble).

B. Public Docket

The Docket for this regulatory action is A–97–35. The docket is an organized and complete file of all the information submitted to or otherwise considered by EPA in the development of this proposed rulemaking. The principal purposes of the docket are: (1) to allow interested parties a means to identify and locate documents so that they can effectively participate in the rulemaking process, and (2) to serve as the record in case of judicial review. The docket is available for public inspection at EPA's Air Docket, which is listed under the **ADDRESSES** section of this preamble.

C. Executive Order 12866

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Administrator must determine whether the regulatory action is ''significant'' and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines ''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 affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local or tribal governments or communities;

(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.

This proposed rule is not expected to have an annual effect on the economy of $100 million or more. However, pursuant to the terms of Executive Order 12866, it has been determined that this proposed rule is a significant action because it raises novel policy issues. As such, the proposed rule has been submitted for OMB review. Any written comments from OMB and any EPA response to OMB comments are in the public docket for this proposal.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), P.L. 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of the UMRA generally requires EPA 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 EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments

to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

This proposed rule is not expected to result in expenditures of more than $100 million in any one year and, as such, is not subject to section 202 of the UMRA. Although the proposed rule is not expected to significantly or uniquely affect small governments, the Agency has notified all potentially affected small governments that own or operate units potentially affected by the proposal in order to assure that they have the opportunity to have meaningful and timely input on the proposed rule. EPA will continue to use its outreach efforts related to part 75 implementation, including a policy manual that is generally updated on a quarterly basis, to inform, educate, and advise all potentially impacted small governments about compliance with part 75.

E. Paperwork Reduction Act

The information collection requirements in this proposal have been submitted for approval to the OMB under the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* An Information Collection Request (ICR) document has been prepared by EPA (ICR No. 1835.01), and a copy may be obtained from Sandy Farmer, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M Street, SW, Washington, DC 20460, by calling (202) 260–2740, or via the Internet at www.gov/icr.

Currently, all affected utilities are required to keep records and submit electronic quarterly reports under the provisions of part 75. The proposed rule includes several new options for compliance with part 75 which have been requested by affected utilities. To implement these options, EPA would have to modify the existing recordkeeping and reporting requirements. In some circumstances, these changes would result in significant reductions in the reporting and recordkeeping burdens or costs for some units (such as low mass emissions units). However, these changes would require modifications to the software used to generate electronic reports. In addition, there would be some increased burden or costs for certain units to fulfill the new quality assurance procedures proposed in these proposed revisions. Finally, several other technical revisions to the existing reporting and recordkeeping requirements have been proposed to clarify existing provisions or to facilitate reporting for other regulatory programs in the context of Acid Rain Program reporting. Although these one-time software changes would tend to increase the short-term burdens allocated to the Acid Rain Program, such changes should reduce a source's overall long-term burden by streamlining the source's reporting obligations under both the Acid Rain Program and the Act.

The average annual projected hour burden is 2,608,836, which is based on an estimated 835 likely respondents (on a per utility basis). The projected cost burden resulting from the collection of information is $47,555,000, which includes a total projected capital and start-up cost of $1,436,000 (for monitoring equipment/software), and a total projected operation and maintenance cost (which includes purchase of testing contractor services and total projected fuel sampling and analysis cost of $716,000) of $46,119,000. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, disclose, or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

An agency may not conduct or sponsor and a person is not required to respond to a collection of information, unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations are listed in 40 CFR part 9 and 48 CFR chapter 15.

Comments are requested on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques. Send comments on the ICR to the Director, OPPE Regulatory Information Division; U.S. Environmental Protection Agency (2137); 401 M Street, SW, Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503, marked ''Attention: Desk Officer for EPA.'' Include the ICR number in any correspondence. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after May 21, 1998, a comment to OMB is best assured of having its full effect if OMB receives it by June 22, 1998. The final rule will respond to any OMB or public comments on the information collection requirements contained in this proposal.

F. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), 5 U.S.C. 601, *et seq.*, 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 governmental jurisdictions. This proposed rule would not have a significant impact on a substantial number of small entities.

Today's proposed revisions to part 75 result in a net cost reduction to utilities affected by the Acid Rain Program, including small entities. Most importantly, the proposed changes to Appendix D and the addition of an optional calculation procedure instead of actual monitoring for oil- and gas-fired units with low mass emissions would significantly reduce the cost of complying with part 75 for oil-and gas-fired units, many of which are owned or operated by small entities. Therefore, I certify this action will not have a significant economic impact on a substantial number of small entities.

G. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''ANTTAA''), Pub L. No. 104–113 15 USC 272 note, directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, business practices, etc.) that are developed or adopted by voluntary consensus standards bodies. The NTTAA requires EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This regulatory action proposes to incorporate by reference voluntary consensus standards pursuant to § 12(d) of the NTTAA. The EPA has adopted the general policy of using voluntary

consensus standards from technically knowledgeable groups such as the Organization for International Standards (ISO), the American Society for Testing and Materials (ASTM), the American Society of Mechanical Engineers (ASME), the American Gas Association (AGA), the Gas Processors Association (GPA), and the American Petroleum Institute (API).

EPA invites public comment on the voluntary consensus standards which are proposed to be incorporated by reference for use in part 75. EPA has not identified any additional voluntary consensus standards which might be applicable to this rulemaking. This does not indicate that other applicable standards do not exist or that any other standards should not be allowed. Therefore, EPA also invites public comment on any other voluntary consensus standards which may be appropriate for the proposed regulatory action. Further, if additional applicable voluntary consensus standards are identified in the future, the designated representative may petition under § 75.66(c) to use an alternative to any standard incorporated by reference and prescribed in this part.

EPA proposes to incorporate by reference the following voluntary consensus standards for use under part 75:

a. ASTM D5373–93 ''Standard Methods for Instrumental Determination of Carbon, Hydrogen and Nitrogen in laboratory samples of Coal and Coke.'' This standard is proposed to be incorporated by reference for use under section 2.1 of Appendix G to part 75 and is discussed further in section III.Q.1 of this preamble.

b. API Section 2 ''Conventional Pipe Provers'' from Chapter 4 of the *Manual of Petroleum Measurement Standards,* October 1988 edition. This standard is proposed to be incorporated by reference for use under paragraph (g)(1)(i) of § 75.20 and under section 2.1.5.1 of Appendix D to part 75. The proposal to incorporate this standard by reference is discussed further in section III.P.6.(b) of this preamble.

List of Subjects in 40 CFR Parts 72 and 75

Air pollution control, Carbon dioxide, Continuous emission monitors, Electric utilities, Environmental protection, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: April 27, 1998.

Carol M. Browner,

Administrator, U.S. Environmental Protection Agency.

For the reasons set out in the preamble, title 40 chapter 1 of the Code of Federal Regulations is proposed to be amended as follows:

PART 72—PERMITS REGULATION

1. The authority for part 72 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

2. Section 72.2 is amended by revising the definitions of ''calibration gas,'' ''excepted monitoring system,'' ''gas-fired,'' ''pipeline natural gas,'' ''span,'' ''stationary gas turbine,'' and ''zero air material''; by revising paragraph (2) of ''oil-fired'' and paragraph (2) of the ''peaking unit''; by adding paragraph (3) to the definition of ''peaking unit''; by adding new definitions for ''conditionally valid data,'' ''EPA protocol gas,'' ''gas manufacturer's intermediate standard,'' ''low mass emissions unit,'' ''maximum rated hourly heat input,'' ''ozone season,'' ''probationary calibration error test,'' ''research gas mixture (RGM)'', and ''standard reference material-equivalent compressed gas primary reference material''; and by removing the definition of ''protocol 1 gas,'' to read as follows:

§ 72.2 Definitions.

* * * * *

Calibration gas means:

(1) A standard reference material;

(2) A standard reference material-equivalent compressed gas primary reference material;

(3) A NIST traceable reference material;

(4) NIST/EPA-approved certified reference materials;

(5) A gas manufacturer's intermediate standard;

(6) An EPA protocol gas;

(7) Zero air material; or

(8) A research gas mixture.

* * * * *

Conditionally valid data means data from a continuous monitoring system that are not quality assured, but which may become quality assured if certain conditions are met. Examples of data that may qualify as conditionally valid are: data recorded by an uncertified monitoring system prior to its initial certification; or data recorded by a certified monitoring system following a significant change to the system that may affect its ability to accurately measure and record emissions. A monitoring system must pass a probationary calibration error test, in accordance with section 2.1.1 of appendix B of part 75 of this chapter, to initiate the conditionally valid data status. In order for conditionally valid emission data to become quality assured, one or more quality assurance tests or diagnostic tests must be passed within a specified time period.

* * * * *

EPA protocol gas means a calibration gas mixture prepared and analyzed according to section 2 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121 or such revised procedure as approved by the Administrator.

* * * * *

Excepted monitoring system means a monitoring system that follows the procedures and requirements of § 75.19 of this chapter or of appendix D or E to part 75 for approved exceptions to the use of continuous emission monitoring systems.

* * * * *

Gas-fired means:

(1) For all purposes under the Acid Rain Program, except for part 75 of this chapter, the combustion of:

(i) Natural gas or other gaseous fuel (including coal-derived gaseous fuel), for at least 90.0 percent of the unit's average annual heat input during the previous three calendar years and for at least 85.0 percent of the annual heat input in each of those calendar years; and

(ii) Any fuel, except coal or solid or liquid coal-derived fuel for the remaining heat input, if any.

(2) For purposes of part 75 of this chapter, the combustion of:

(i) Natural gas or other gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas (including coal-derived gaseous fuel) for at least 90.0 percent of the unit's average annual heat input during the previous calendar years and for at least 85.0 percent of the annual heat input in each of those calendar years; and

(ii) Fuel oil, for the remaining heat input, if any.

(3) For purposes of part 75 of this chapter, a unit may initially qualify as gas-fired if the designated representative demonstrates to the satisfaction of the Administrator that the requirements of paragraph (2) of this definition are met, or will in the future be met, through one of the following submissions:

(i) For a unit for which a monitoring plan has not been submitted under § 75.62 of this chapter,

(A) The designated representative submits fuel usage data for the unit for

the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under § 75.62; or

(B) For a unit that does not have fuel usage data for one or more of the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under § 75.62, if the designated representative submits: the unit's designated fuel usage; all available fuel usage data (including the percentage of the unit's heat input derived from the combustion of gaseous fuels), beginning with the date on which the unit commenced commercial operation; and the unit's projected fuel usage.

(ii) For a unit for which a monitoring plan has already been submitted under § 75.62, that has not qualified as gas-fired under paragraph (3)(i) of this definition, and whose fuel usage changes, the designated representative submits either:

(A) Three calendar years of data following the change in the unit's fuel usage, showing that no less than 90.0 percent of the unit's average annual heat input during the previous three calendar years, and no less than 85.0 percent of the unit's annual heat input during any one of the previous three calendar years is from the combustion of gaseous fuels with a total sulfur content no greater than the total sulfur content of natural gas and the remaining heat input is from the combustion of fuel oil; or

(B) A minimum of 720 hours of unit operating data following the change in the unit's fuel usage, showing that no less than 90.0 percent of the unit's heat input is from the combustion of gaseous fuels with a total sulfur content no greater than the total sulfur content of natural gas and the remaining heat input is from the combustion of fuel oil, and a statement that this changed pattern of fuel usage is considered permanent and is projected to continue for the foreseeable future.

(iii) If a unit qualifies as gas-fired under paragraph (2)(i) or (ii) of this definition, the unit is classified as gas-fired as of the date of the submission under such paragraph.

(4) For purposes of part 75 of this chapter, a unit that initially qualifies as gas-fired must meet the criteria in paragraph (2) of this definition each year in order to continue to qualify as gas-fired. If such a unit fails to meet such criteria for a given year, the unit no longer qualifies as gas-fired starting January 1 of the year after the first year for which the criteria are not met. If a unit failing to meet the criteria in paragraph (2) of this definition initially qualified as a gas-fired unit under paragraph (3)(ii) of this definition, the unit may qualify as a gas-fired unit for a subsequent year only under paragraph (3)(i) of this definition.

* * * * *

Gas manufacturer's intermediate standard (GMIS) means a compressed gas calibration standard that has been assayed and certified by direct comparison to a standard reference material (SRM), an SRM-equivalent PRM, a NIST/EPA-approved certified reference material (CRM), or a NIST traceable reference material (NTRM), in accordance with section 2.1.2.1 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121.

* * * * *

Low mass emissions unit means a gas-fired or oil-fired unit that burns only natural gas and/or fuel oil and that qualifies under §§ 75.19(a) and (b) of this chapter.

* * * * *

Maximum rated hourly heat input means a unit-specific maximum hourly heat input (mmBtu) which is the higher of the manufacturer's maximum rated hourly heat input or the highest observed hourly heat input.

Oil-fired means:

* * * * *

(2) For purposes of part 75 of this chapter, a unit may qualify as oil-fired if the unit burns only fuel oil and gaseous fuels with a total sulfur content no greater than the total sulfur content of natural gas and if the unit does not meet the definition of gas-fired.

* * * * *

Ozone season means the period of time from May 1st to September 30th, inclusive.

* * * * *

Peaking unit means:

* * * * *

(2) For purposes of part 75 of this chapter, a unit may initially qualify as a peaking unit if the designated representative demonstrates to the satisfaction of the Administrator that the requirements of paragraph (1) of this definition are met, or will in the future be met, through one of the following submissions:

(i) For a unit for which a monitoring plan has not been submitted under § 75.62,

(A) The designated representative submits capacity factor data for the unit for the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under § 75.62; or

(B) For a unit that does not have capacity factor data for one or more of the three calendar years immediately preceding the date of initial submission of the monitoring plan for the unit under § 75.62, the designated representative submits: all available capacity factor data, beginning with the date on which the unit commenced commercial operation; and projected capacity factor.

(ii) For a unit for which a monitoring plan has already been submitted under § 75.62, that has not qualified as a peaking unit under paragraph (2)(i) of this definition, and where capacity factor changes, the designated representative submits either:

(A) Three calendar years of data following the change in the unit's capacity factor showing an average capacity factor of no more than 10.0 percent during the three previous calendar years and a capacity factor of no more than 20.0 percent in each of those calendar years; or

(B) One calendar year of data following the change in the unit's capacity factor showing a capacity factor of no more than 10.0 percent and a statement that this changed pattern of operation resulting in a capacity factor less than 10.0 percent is considered permanent and is projected to continue for the foreseeable future.

(3) For purposes of part 75 of this chapter, a unit that initially qualifies as a peaking unit must meet the criteria in paragraph (1) of this definition each year in order to continue to qualify as a peaking unit. If such a unit fails to meet such criteria for a given year, the unit no longer qualifies as a peaking unit starting January 1 of the year after the year for which the criteria are not met. If a unit failing to meet the criteria in paragraph (1) of this definition initially qualified as a gas-fired unit under paragraph (2)(ii) of this definition, the unit may qualify as a peaking unit for a subsequent year only under paragraph (2)(i) of this definition.

* * * * *

Pipeline natural gas means natural gas that is provided by a supplier through a pipeline and that contains 0.3 grains or less of hydrogen sulfide per 100 standard cubic feet. The hydrogen sulfide content of the natural gas must be documented either through quality characteristics specified by a purchase contract or pipeline transportation contract, through certification of the gas vendor, based on routine vendor sampling and analysis, or through at least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken at least monthly, demonstrating that all samples contain

0.3 grains or less of hydrogen sulfide per 100 standard cubic feet.

* * * * *

Probationary calibration error test means an on-line calibration error test performed in accordance with section 2.1.1 of appendix B of part 75 of this chapter that is used to initiate a conditionally valid data period.

* * * * *

Research gas mixture (RGM) means a calibration gas mixture developed by agreement of a requestor and NIST that NIST analyzes and certifies as ''NIST traceable.'' RGMs may have concentrations different from those of standard reference materials.

* * * * *

Span means the highest pollutant or diluent concentration or flow rate that a monitor component is required to be capable of measuring under part 75 of this chapter.

* * * * *

Standard reference material-equivalent compressed gas primary reference material (SRM-equivalent PRM) means those gas mixtures listed in a declaration of equivalence in accordance with section 2.1.2 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121.

* * * * *

Stationary gas turbine means a turbine that is not self-propelled and that combusts natural gas, other gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas, or fuel oil in order to heat inlet combustion air and thereby turn a turbine, in addition to or instead of producing steam or heating water.

* * * * *

Zero air material means either:

(1) A calibration gas certified by the gas vendor not to contain concentrations of SO_2, NO_X, or total hydrocarbons above 0.1 parts per million (ppm), a concentration of CO above 1 ppm, a concentration of CO_2 above 400 ppm; or

(2) Ambient air conditioned and purified by a CEMS for which the CEMS manufacturer or vendor certifies that the particular CEMS model produces conditioned gas that does not contain concentrations of SO_2, NO_X, or total hydrocarbons above 0.1 ppm, a concentration of CO above 1 ppm, or a concentration of CO_2 above 400 ppm; or

(3) For dilution-type CEMS, conditioned and purified ambient air provided by a conditioning system concurrently supplying dilution air to the CEMS; or

(4) A multicomponent mixture certified by the supplier of the mixture that the concentration of the component being zeroed is less than or equal to the applicable concentration specified in paragraph (1) of this definition, and that the mixture's other components do not interfere with the specific CEM readings or cause the CEM being zeroed to read concentrations of the gas being zeroed.

3. Section 72.3 is amended by adding in alphabetical order, new acronyms for kacfm, kscfh, and NIST to read as follows:

§ 72.3 Measurements, abbreviations, and acronyms.

* * * * *

kacfm—thousands of cubic feet per minute at actual conditions.

kscfh—thousands of cubic feet per hour at standard conditions.

NIST—National Institute of Standards and Technology.

* * * * *

§ 72.6 [Amended]

4. Section 72.6 is amended by removing from paragraph (b)(1) the word ''operation'' and adding, in its place, the words ''commercial operation.''

5. Section 72.90 is amended by revising paragraph (c)(3) to read as follows:

§ 72.90 Annual compliance certification report.

* * * * *

(c) * * *

(3) Whether all the emissions from the unit, or a group of units (including the unit) using a common stack, were monitored or accounted for through the missing data procedures and reported in the quarterly monitoring reports, including whether conditional data were reported in the quarterly report. If conditional data were reported, the owner or operator shall indicate whether the status of all conditional data has been resolved and all necessary quarterly report resubmissions have been made.

* * * * *

PART 75—CONTINUOUS EMISSION MONITORING

6. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651k.

7. Section 75.1 is amended by revising paragraph (a) to read as follows:

§ 75.1 Purpose and scope.

(a) *Purpose.* The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide, nitrogen oxides, and carbon dioxide emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to Sections 412 and 821 of the Clean Air Act, 42 U.S.C. 7401-7671q as amended by Public Law 101–549 (November 15, 1990) (the Act). In addition, this part sets forth provisions for the monitoring, recordkeeping, and reporting of NO_X mass emissions with which EPA, individual States, or groups of States may require sources to comply in order to demonstrate compliance with a NO_X mass emission reduction program, if these provisions are adopted as requirements under such a program.

* * * * *

8. Section 75.2 is amended by revising paragraph (a) and adding a new paragraph (c) to read as follows:

§ 75.2 Applicability.

(a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO_2 or NO_X.

* * * * *

(c) The provisions of this part may apply to sources subject to a State or federal NO_X mass emission reduction program, if these provisions are adopted as requirements under such a program.

9. Section 75.4 is amended by revising paragraphs (a) introductory text and (d)(1) and adding a new paragraph (i) to read as follows:

§ 75.4 Compliance dates.

(a) The provisions of this part apply to each existing Phase I and Phase II unit on February 10, 1993. For substitution or compensating units that are so designated under the Acid Rain permit which governs that unit and contains the approved substitution or reduced utilization plan, pursuant to § 72.41 or § 72.43 of this chapter, the provisions of this part become applicable upon the issuance date of the Acid Rain permit. For combustion sources seeking to enter the Opt-in Program in accordance with part 74 of this chapter, the provisions of this part become applicable upon the submission of an Opt-in permit application in accordance with § 74.14 of this chapter. The provisions of this part for the monitoring, recording, and reporting of NO_X mass emissions become applicable on the deadlines specified in the applicable State or federal NO_X mass emission reduction program, if these provisions are adopted as requirements under such a program. In accordance with § 75.20, the owner or operator of each existing affected unit shall ensure that all monitoring systems required by

this part for monitoring SO_2, NO_X, CO_2, opacity, and volumetric flow are installed and that all certification tests are completed no later than the following dates (except as provided in paragraphs (d) through (h) of this section):

* * * * *

(d) * * *

(1) The maximum potential concentration of SO_2, the maximum potential NO_X emission rate, the maximum potential flow rate, as defined in section 2.1 of appendix A to this part, or the maximum potential CO_2 concentration, as defined in section 2.1.3.1 of appendix A to this part.

* * * * *

(i) In accordance with § 75.20, the owner or operator of each affected unit at which SO_2 concentration is measured on a dry basis or at which moisture corrections are required to account for CO_2 emissions, NO_X emission rate in lb/mmBtu, or heat input, shall ensure that the continuous moisture monitoring system required by this part is installed and that all applicable initial certification tests required under § 75.20(c)(5), (c)(6), or (c)(7) for the continuous moisture monitoring system are completed no later than the following dates:

(1) January 1, 2000, for a unit that is existing and has commenced commercial operation by October 3, 1999; or

(2) For a new affected unit which has not commenced commercial operation by October 4, 1999, not later than 90 days after the date the unit commences commercial operation; or

(3) For an existing unit that is shutdown and is not yet operating by January 1, 2000, not later than the earlier of 45 unit operating days or 180 calendar days after the date that the unit recommences commercial operation.

10. Section 75.5 is amended by revising paragraph (f)(2) to read as follows:

§ 75.5 Prohibitions.

* * * * *

(f) * * *

(2) The owner or operator is monitoring emissions from the unit with another certified monitoring system or an excepted methodology approved by the Administrator for use at that unit that provides emission data for the same pollutant or parameter as the retired or discontinued monitoring system; or

* * * * *

11. Section 75.6 is amended by redesignating paragraph (a)(40) as paragraph (a)(41) and by adding new paragraphs (a)(40) and (f) to read as follows:

§ 75.6 Incorporation by reference.

* * * * *

(a) * * *

(40) ASTM D5373–93, ''Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke,'' for appendix G to this part.

* * * * *

(f) The following materials are available for purchase from the following address: American Petroleum Institute, Publications Department, 1220 L Street NW, Washington, DC 20005–4070: American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993), for § 75.20 and appendix D to this part.

12. Section 75.10 is amended by revising paragraphs (d)(3) and (f) to read as follows:

§ 75.10 General operating requirements.

* * * * *

(d) * * *

(3) Failure of an SO_2, CO_2, or O_2 pollutant concentration monitor, flow monitor, or NO_X continuous emission monitoring system to acquire the minimum number of data points for calculation of an hourly average in paragraph (d)(1) of this section, shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. An hourly average NO_X or SO_2 emission rate in lb/mmBtu is valid only if the minimum number of data points is acquired by both the pollutant concentration monitor (NO_X or SO_2) and the diluent monitor (O_2 or CO_2). For a moisture monitoring system consisting of one or more oxygen analyzers capable of measuring O_2 on a wet-basis and a dry-basis, an hourly average percent moisture value is valid only if the minimum number of data points is acquired for both the wet-and dry-basis measurements. Except for SO_2 emission rate data in lb/mmBtu, if a valid hour of data is not obtained, the owner or operator shall estimate and record emission, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in subpart D of this part.

* * * * *

(f) *Minimum measurement capability requirement.* The owner or operator shall ensure that each continuous emission monitoring system and component thereof is capable of accurately measuring, recording, and reporting data, and shall not incur a full scale exceedance, except as provided in sections 2.1.1.5, 2.1.2.5, and 2.1.4.3 of appendix A to this part.

* * * * *

13. Section 75.11 is amended by revising paragraphs (a), (b), (d)(1), (d)(2), (e)(2), (e)(3) introductory text, (e)(3)(ii), (e)(3)(iv), and (e)(4) and by adding paragraph (d)(3), to read as follows:

§ 75.11 Specific provisions for monitoring SO_2 emissions (SO_2 and flow monitors).

(a) *Coal-fired units.* The owner or operator shall meet the general operating requirements in § 75.10 for an SO_2 continuous emission monitoring system and a flow monitoring system for each affected coal-fired unit while the unit is combusting coal and/or any other fuel, except as provided in paragraph (e) of this section, in § 75.16, and in subpart E of this part. During hours in which only natural gas or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 20 grains per 100 standard cubic feet (gr/100 scf)) is combusted in the unit, the owner or operator shall comply with the applicable provisions of paragraph (e)(1), (e)(2), or (e)(3) of this section.

(b) *Moisture correction.* Where SO_2 concentration is measured on a dry basis, the owner or operator shall install, operate, maintain, and quality assure a continuous moisture monitoring system for measuring and recording the moisture content of the flue gases, in order to correct the measured hourly volumetric flow rates for moisture when calculating SO_2 mass emissions (in lb/hr) using the procedures in appendix F to this part. The following continuous moisture monitoring systems are acceptable: a continuous moisture sensor; an oxygen analyzer (or analyzers) capable of measuring O_2 both on a wet basis and on a dry basis; or a stack temperature sensor and a moisture look-up table, i.e., a psychrometric chart (for saturated gas streams following wet scrubbers, only). The moisture monitoring system shall include as a component the automated data acquisition and handling system (DAHS) for recording and reporting both the raw data (e.g., hourly average wet and dry-basis O_2 values) and the hourly average values of the stack gas moisture content derived from those data. When a moisture look-up table is used, the moisture monitoring system shall be represented as a single component, the certified DAHS, in the monitoring plan for the unit or common stack.

* * * * *

(d) * * *

(1) By meeting the general operating requirements in § 75.10 for an SO_2 continuous emission monitoring system

and flow monitoring system. If this option is selected, the owner or operator shall comply with the applicable provisions in paragraph (e)(1), (e)(2), or (e)(3) of this section during hours in which the unit combusts only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas);

(2) By providing other information satisfactory to the Administrator using the applicable procedures specified in appendix D to this part for estimating hourly SO_2 mass emissions. Appendix D shall not, however, be used when the unit combusts gaseous fuel with a total sulfur content greater than the total sulfur content of natural gas (i.e., > 20 gr/100 scf); when such fuel is burned, the owner or operator shall comply with the provisions of paragraph (e)(4) of this section; or

(3) By using the low mass emissions excepted methodology in § 75.19(c) for estimating hourly SO_2 mass emissions if the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b).

(e) * * *

(2) When gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 20 gr/100 scf) is combusted in the unit, the owner or operator may, in lieu of operating and recording data from the SO_2 monitoring system, determine SO_2 emissions by certifying an excepted monitoring system in accordance with § 75.20 and with appendix D to this part, by following the fuel sampling and analysis procedures in section 2.3.1 of appendix D to this part, by meeting the recordkeeping requirements of § 75.55 or § 75.58, as applicable, and by meeting all quality control and quality assurance requirements for fuel flowmeters in appendix D to this part. If this compliance option is selected, the hourly unit heat input reported under § 75.54(b)(5) or § 75.57(b)(5), as applicable, shall be determined using a certified flow monitoring system and a certified diluent monitor, in accordance with the procedures in section 5.2 of appendix F of this part. The flow monitor and diluent monitor shall meet all of the applicable quality control and quality assurance requirements of appendix B of this part.

(3) When gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 20 gr/100 scf) is burned in the unit, the owner or operator may determine SO_2 mass emissions by using a certified SO_2 continuous monitoring system, in conjunction with a certified flow rate monitoring system. However, on and after January 1, 2000, the SO_2 monitoring system shall be subject to the following provisions; prior to January 1, 2000, the owner or operator may comply with these provisions:

* * * * *

(ii) The calibration response of the SO_2 monitoring system shall be adjusted, either automatically or manually, in accordance with the procedures for routine calibration adjustments in section 2.1.3 of appendix B to this part, whenever the zero-level calibration response during a required daily calibration error test exceeds the applicable performance specification of the instrument in section 3.1 of appendix A to this part (i.e., ± 2.5 percent of the span value or ± 5 ppm, whichever is less restrictive). This calibration adjustment is optional if gaseous fuel is burned in the affected unit only during unit startup.

* * * * *

(iv) In accordance with the requirements of section 2.1.1.2 of appendix A to this part, for units that sometimes burn natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) and at other times burn higher-sulfur fuel(s) such as coal or oil, a second low-scale SO_2 measurement range is not required when natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) is combusted. For units that burn only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) and burn no other type(s) of fuel(s), the owner or operator shall set the span of the SO_2 monitoring system to a value no greater than 200 ppm.

(4) During any hours in which a unit combusts only gaseous fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 20 gr/100 scf), the owner or operator shall meet the general operating requirements in § 75.10 for an SO_2 continuous emission monitoring system and a flow monitoring system.

* * * * *

14. Section 75.12 is amended by revising the title; by redesignating existing paragraphs (b), (c), and (d) as paragraphs (c), (d), and (f), respectively; by adding new paragraphs (b) and (e); and by revising the newly designated paragraph (c), to read as follows:

§ 75.12 Specific provisions for monitoring NO_X emission rate (NO_X and diluent gas monitors).

* * * * *

(b) *Moisture correction*. If a correction for the stack gas moisture content is needed to properly calculate the NO_X emission rate in lb/mmBtu, i.e., if the NO_X pollutant concentration monitor measures on a different moisture basis from the diluent monitor, the owner or operator shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in § 75.11(b).

(c) *Determination of NO_X emission rate*. The owner or operator shall calculate hourly, quarterly, and annual NO_X emission rates (in lb/mmBtu) by combining the NO_X concentration (in ppm), diluent concentration (in percent O_2 or CO_2), and percent moisture (if applicable) measurements according to the procedures in appendix F to this part.

* * * * *

(e) *Low mass emissions units*. Notwithstanding the requirements of §§ 75.12(a) and (c), the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a NO_X continuous emission monitoring system;

(2) Meet the requirements specified in paragraph (d)(2) of this section for using the excepted monitoring procedures in appendix E to this part, if applicable; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly NO_X emission rate and hourly NO_X mass emissions.

* * * * *

15. Section 75.13 is amended by revising paragraphs (a) and (c) and by adding paragraph (d) to read as follows:

§ 75.13 Specific provisions for monitoring CO_2 emissions.

(a) *CO_2 continuous emission monitoring system*. If the owner or operator chooses to use the continuous emission monitoring method, then the owner or operator shall meet the general operating requirements in § 75.10 for a CO_2 continuous emission monitoring system and flow monitoring system for each affected unit. The owner or operator shall comply with the applicable provisions specified in §§ 75.11(a) through (e) or § 75.16, except that the phrase ''SO_2 continuous emission monitoring system'' is replaced with ''CO_2 continuous emission monitoring system,'' the phrase ''SO_2 concentration'' is replaced with ''CO_2 concentration,'' the term ''maximum potential concentration of SO_2'' is replaced with ''maximum potential concentration of CO_2,'' and the phrase ''SO_2 mass emissions'' is replaced with ''CO_2 mass emissions.''

* * * * *

(c) *Determination of CO_2 mass emissions using an O_2* monitor

according to appendix F. If the owner or operator chooses to use the appendix F method, then the owner or operator may determine hourly CO_2 concentration and mass emissions with a flow monitoring system; a continuous O_2 concentration monitor; fuel F and F_c factors; and, where O_2 concentration is measured on a dry basis, a continuous moisture monitoring system, as defined in § 75.11(b), using the methods and procedures specified in appendix F to this part. For units using a common stack, multiple stack, or bypass stack, the owner or operator may use the provisions of § 75.16, except that the phrase ''SO_2 continuous emission monitoring system'' is replaced with ''CO_2 continuous emission monitoring system,'' the term ''maximum potential concentration of SO_2'' is replaced with ''maximum potential concentration of CO_2,'' and the phrase ''SO_2 mass emissions'' is replaced with ''CO_2 mass emissions.''

(d) *Determination of CO_2 mass emissions from low mass emissions units.* The owner or operator of a unit that qualifies as a low mass emissions unit under §§ 75.19(a) and (b) shall comply with one of the following:

(1) Meet the general operating requirements in § 75.10 for a CO_2 continuous emission monitoring system and flow monitoring system;

(2) Meet the requirements specified in paragraph (b) or (c) of this section for use of the methods in appendix G or F to this part, respectively; or

(3) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly CO_2 mass emissions.

16. Section 75.16 is amended by:

a. Revising paragraphs (b)(2)(ii)(B), (b)(2)(ii)(D), (d)(2), and (e)(1);

b. Removing paragraphs (e)(2) and (e)(3);

c. Redesignating existing paragraphs (e)(4) and (e)(5) as paragraphs (e)(2) and (e)(3), respectively;

d. Revising the last sentence and adding a new sentence to the end of the newly designated paragraph (e)(3); and

e. Adding a new paragraph (e)(4), to read as follows:

§ 75.16 Special provisions for monitoring emissions from common, bypass, and multiple stacks for SO_2 emissions and heat input determinations.

* * * * *

(b) * * *

(2) * * *

(ii) * * *

(B) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system and flow monitoring system in the duct from each nonaffected unit; determine SO_2 mass emissions from the affected units as the difference between SO_2 mass emissions measured in the common stack and SO_2 mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly average value less than zero; combine emissions for the Phase I and Phase II affected units for recordkeeping and compliance purposes; calculate and report SO_2 mass emissions from the Phase I and Phase II affected units, pursuant to an approach approved by the Administrator, such that these emissions are not underestimated; or

* * * * *

(D) Petition through the designated representative and provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions measured in the common stack to each of the units using the common stack and on reporting the SO_2 mass emissions. The Administrator may approve such demonstrated substitute methods for apportioning and reporting SO_2 mass emissions measured in a common stack whenever the demonstration ensures that there is a complete and accurate accounting of all emissions regulated under this part and, in particular, that the emissions from any affected unit are not underestimated.

* * * * *

(d) * * *

(2) Install, certify, operate, and maintain an SO_2 continuous emission monitoring system and flow monitoring system in each stack. Determine SO_2 mass emissions from each affected unit as the sum of the SO_2 mass emissions recorded for each stack. Notwithstanding the prior sentence, if another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable common stack requirements of this section to determine and record SO_2 mass emissions from the units using that stack and shall calculate and report SO_2 mass emissions from the affected units and stacks, pursuant to an approach approved by the Administrator, such that these emissions are not underestimated.

(e) * * *

(1) The owner or operator of an affected unit using a common stack, bypass stack, or multiple stack with a diluent monitor and a flow monitor on each stack may choose to install monitors to determine the heat input for the affected unit, wherever flow and diluent monitor measurements are used to determine the heat input, using the procedures specified in paragraphs (a) through (d) of this section, except that the terms ''SO_2 mass emissions'' and ''emissions'' are replaced with the term ''heat input'' and the phrase ''SO_2 continuous emission monitoring system and flow monitoring system'' is replaced with the phrase ''a diluent monitor and a flow monitor.'' The applicable equation in appendix F to this part shall be used to calculate the heat input from the hourly flow rate, diluent monitor measurements, and (if the equation in appendix F requires a correction for the stack gas moisture content) hourly moisture measurements. Notwithstanding the options for combining heat input in paragraphs (a)(1)(ii), (a)(2)(ii), (b)(1)(ii), and (b)(2)(ii) of this section, the owner or operator of an affected unit with a diluent monitor and a flow monitor installed on a common stack to determine the combined heat input at the common stack shall also determine and report heat input to each individual unit.

* * * * *

(3) * * * The heat input may be apportioned either by using the ratio of load (in MWe-hr) for each individual unit to the total load for all units utilizing the common stack or by using the ratio of steam flow (in 1000 lb) for each individual unit to the total steam flow for all units utilizing the common stack. The heat input should be apportioned according to the procedures in appendix F to this part.

(4) Notwithstanding paragraph (e)(1) of this section, any affected unit that is using the procedures in this part to meet the monitoring and reporting requirements of a State or federal NO_X mass emission reduction program must also meet the requirements for monitoring heat input in §§ 75.71 and 75.72.

17. Section 75.17 is amended by adding introductory text before paragraph (a) and by revising paragraph (a)(2)(i)(C) to read as follows:

§ 75.17 Specific provisions for monitoring emissions from common, by-pass, and multiple stacks for NO_X emission rate.

Notwithstanding the provisions of paragraphs (a), (b), and (c) of this section, the owner or operator of an affected unit that is using the procedures in this part to meet the monitoring and reporting requirements of a State or federal NO_X mass emission reduction program must also meet the provisions for monitoring NO_X emission rate in §§ 75.71 and 75.72.

(a) * * *

(2) * * *

(i) * * *

(C) Each unit's compliance with the applicable NO_X emission limit will be determined by a method satisfactory to

the Administrator for apportioning to each of the units the combined NO_X emission rate (in lb/mmBtu) measured in the common stack and for reporting the NO_X emission rate, as provided in a petition submitted by the designated representative. The Administrator may approve such demonstrated substitute methods for apportioning and reporting NO_X emission rate measured in a common stack whenever the demonstration ensures that there is a complete and accurate estimation of all emissions regulated under this part and, in particular, that the emissions from any unit with a NO_X emission limitation are not underestimated.

* * * * *

18. Section 75.19 is added to subpart B to read as follows:

§ 75.19 Optional SO_2, NO_X, and CO_2 emissions calculation for low mass emissions units.

(a) *Applicability.* (1) Consistent with the requirements of paragraphs (a)(2) and (b) of this section, the low mass emissions excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of excepted methods under appendix D or E to this part, for the purpose of determining hourly heat input, hourly NO_X emission rate, and hourly NO_X, SO_2, and CO_2 mass emissions from a low mass emissions unit. A low mass emissions unit is a gas-fired or oil-fired unit that burns only natural gas and/or fuel oil and that:

(i) Emits no more than 25 tons of SO_2 annually and no more than 25 tons of NO_X annually; and

(ii) Has calculated emissions of no more than 25 tons of SO_2 annually and no more than 25 tons of NO_X annually based on the maximum rated hourly heat input, the actual operating time for each fuel burned, and the low mass emissions excepted methodology, calculations, and values in paragraph (c) of this section.

(2) A unit may initially qualify as a low mass emissions unit only under the following circumstances:

(i) The designated representative provides historical actual and calculated emissions data from the previous three calendar years immediately prior to the submission of an application to use the low mass emissions excepted methodology, and the data demonstrates to the satisfaction of the Administrator that the unit meets the criteria in paragraphs (a)(1)(i) and (ii) of this section; or

(ii) If a unit does not have the historical data required in paragraph (a)(2)(i) of this section for any one or more of the previous three calendar years, the designated representative submits:

(A) Any historical annual emissions and operating data, as required in paragraphs (a)(1)(i) and (a)(1)(ii) of this section, beginning with the unit's first calendar year of commercial operation, and the data demonstrates to the satisfaction of the Administrator that the unit meets the criteria in paragraphs (a)(1)(i) and (a)(1)(ii) of this section; and

(B) A demonstration satisfactory to the Administrator that the unit will continue to qualify as a low mass emissions unit under the requirements of this paragraph (a). The demonstration shall include any historical emissions and operating data for less than a calendar year for the unit and projected emissions information for the unit, as determined using projected operating hours and fuel usage, and the low mass emissions excepted methodology, calculations, and values in paragraph (c) of this section.

(b) *Disqualification.* If a unit that initially qualifies as a low mass emissions units under this section changes the fuel that is burned in the unit such that a fuel other than natural gas or fuel oil is combusted in the unit, the unit is disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. In addition, if a unit that initially qualifies as a low mass emissions unit under this section emits more than 25 tons of SO_2 or 25 tons of NO_X in any calendar year or has calculated emissions greater than 25 tons of SO_2 or 25 tons of NO_X in any calendar year, as determined using the low mass emission equations in paragraph (c) of this section, the owner or operator of the unit shall have two quarters from the end of the quarter in which the exceedance occurs to install, certify, and report SO_2, NO_X, and CO_2 from monitoring systems that meet the requirements of §§ 75.11, 75.12, and 75.13, respectively. The unit shall be disqualified as a low mass emissions unit as of the end of the second quarter following the quarter in which either of the 25 ton limits was exceeded. A unit that has been disqualified from using the low mass emissions excepted methodology may subsequently qualify again as a low mass emissions unit under paragraph (a)(2) of this section, provided that if such unit qualified under paragraph (a)(2)(ii) of this section, the unit may subsequently qualify again if the unit meets the requirements of paragraph (a)(2)(i) of this section.

(c) *Low mass emissions excepted methodology, calculations, and values.*—(1) *Operating time.* (i) Report an hourly record if the unit operated for any portion of the hour or if records are missing, as to whether or not the unit operated for any portion of that hour.

(ii) Quarterly operating time (hr) is equal to the sum of all of the reported operating hours in the quarter, such that any hour in which the unit combusted fuel for any portion of the hour is considered a full hour.

(iii) Year-to-date cumulative operating time (hr) is equal to the sum of all of the reported operating hours in the year to date, such that any hour in which the unit combusted fuel for any portion of the hour is considered a full hour.

(2) *Heat input.* (i) Hourly heat input (mmBtu) is equal to the maximum rated hourly heat input, as defined in § 72.2 of this chapter. However, the owner or operator of an affected unit may petition the Administrator under § 75.66 for a lower value for maximum rated hourly heat input than that defined in § 72.2 of this chapter. The Administrator may approve such lower value if the owner or operator demonstrates that either the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(ii) Calculate the quarterly total heat input (mmBtu) using Equation 7a as follows:

$$HI_{qtr} = T_{qtr} \times HI_{hr}$$

(Eq. 7a)

where:

T_{qtr} = Actual number of operating hours in the quarter, in hr.

HI_{hr} = Hourly heat input under paragraph (c)(2)(i) of this section, in mmBtu.

(iii) Calculate the year-to-date cumulative heat input (mmBtu) as the sum of all of the hourly heat input values in the year to date.

(3) SO_2. (i) Calculate the hourly total SO_2 mass emissions (lbs) using Equation 7b and the appropriate fuel-based SO_2 emission factor from Table 1a for the fuel being burned in that hour. If more than one fuel is burned in the hour, use the highest emission factor for all of the fuels burned in the hour. If records are missing as to which fuel was burned in the hour, use the highest emission factor for all of the fuels capable of being burned in that unit.

TABLE 1a.—SO_2 EMISSION FACTORS (LB/MMBTU) FOR VARIOUS FUEL TYPES

Fuel type	SO_2 Emission factors
Pipeline Natural Gas	0.0006 lb/mmBtu.

TABLE 1a.—SO_2 EMISSION FACTORS (LB/MMBTU) FOR VARIOUS FUEL TYPES—Continued

Fuel type	SO_2 Emission factors
Natural Gas	0.06 lb/mmBtu.
Residual Oil	2.1 lb/mmBtu.
Diesel Fuel	0.5 lb/mmBtu.

$W_{SO2} = EF_{SO2} \times HI_{hr}$

(Eq. 7b)

Where:

W_{SO2} = SO_2 mass emissions, in lbs.

EF_{SO2} = Fuel-based SO_2 emission factor from Table 1a of this section, in lb/mmBtu.

HI_{hr} = Hourly heat input under paragraph (c)(2)(i) of this section, in mmBtu.

(ii) Calculate the quarterly total SO_2 mass emissions (tons) by summing all of the hourly SO_2 mass emissions under paragraph (c)(3)(i) of this section in the quarter and dividing by 2000 lb/ton.

(iii) Calculate the year-to-date cumulative SO_2 mass emissions (tons) by summing all of the SO_2 mass emissions under paragraph (c)(3)(i) of this section in the year to date.

(4) NO_X. (i) Determine the hourly NO_X emission rate (lb/mmBtu) by using the appropriate fuel and boiler type default NO_X emission rate in Table 1b for the fuel being burned in that hour. If more than one fuel is burned in the hour, use the highest emission rate for all of the fuels burned in the hour. If records are missing as to which fuel was burned in the hour, use the highest emission factor for all of the fuels capable of being burned in that unit.

TABLE 1b.—NO_X EMISSION RATES (LB/MMBTU) FOR VARIOUS BOILER/FUEL TYPES

Boiler type	Fuel type	NO_X Emission rate
Tangentially fired	Oil	0.366
Tangentially fired	Gas	0.290
Dry Bottom Wall fired	Oil	0.490
Dry Bottom Wall fired	Gas	0.400
Combustion Turbine	Oil	0.258
Combustion Turbine	Gas	0.172
Combined Cycle	Oil	0.273
Combined Cycle	Gas	0.273

(ii) Calculate the hourly total NO_X mass emissions (lbs) as the product of the NO_X emission rate (lb/mmBtu) and hourly heat input (mmBtu), using Equation 7c as follows:

$W_{NOX} = EF_{NOX} \times HI_{hr}$

(Eq. 7c)

where:

W_{NOX} = NO_X mass emissions, in lbs.

EF_{NOX} = Boiler-type and fuel-type NO_X emission factor from Table 1b of this section, in lb/mmBtu.

HI_{hr} = Hourly heat input under paragraph (c)(2)(i) of this section, in mmBtu.

(iii) Calculate the quarterly average NO_X emission rate (lb/mmBtu) by summing all of the hourly NO_X emission rates for the quarter and dividing the total by the number of reported operating hours under paragraph (c)(1)(i) of this section in the quarter.

(iv) Calculate the quarterly total NO_X mass emissions (tons) by summing all of the hourly NO_X mass emissions under paragraph (c)(4)(ii) of this section in the quarter and dividing the total by 2000 lb/ton.

(v) Calculate the year-to-date cumulative average NO_X emission rate (lb/mmBtu) by summing all of the hourly NO_X emission rates for all of the hours in the year to date and dividing the total by the number of reported operating hours under paragraph (c)(1)(i) of this section in the year to date.

(vi) Calculate the year-to-date cumulative NO_X mass emissions total (tons) by summing all of the hourly NO_X mass emissions under paragraph (c)(4)(ii) of this section in the year to date.

(5) *CO_2*. (i) Calculate the hourly total CO_2 mass emissions (tons) using Equation 7d and the appropriate fuel-based CO_2 emission factor from Table 1c for the fuel being burned in that hour. If more than one fuel is burned in the hour, use the highest emission factor for all of the fuels burned in the hour. If records are missing as to which fuel was burned in the hour, use the highest emission factor for all of the fuels capable of being burned in that unit.

TABLE 1c.—CO_2 EMISSION FACTORS (TON/MMBTU) FOR GAS AND OIL

Fuel type	CO_2 emission factors
Natural Gas	0.059 ton/mmBtu.
Oil	0.081 ton/mmBtu.

$W_{CO2}=EF_{CO2} \times HI_{hr}$

(Eq. 7d)

Where:

W_{CO2} = CO_2 mass emissions, in tons.

EF_{CO2} = Fuel-based CO_2 emission factor from Table 1c, in ton/mmBtu.

HI_{hr} = Hourly heat input under paragraph (c)(2)(i) of this section, in mmBtu.

(ii) Calculate the quarterly total CO_2 mass emissions (tons) by summing all of the hourly CO_2 mass emissions under paragraph (c)(5)(i) of this section in the quarter.

(iii) Calculate the year-to-date cumulative CO_2 mass emissions (tons) by summing all of the hourly CO_2 mass emissions under paragraph (c)(5)(i) of this section in the year to date.

(d) The quality control and quality assurance requirements in § 75.21 are not required for a low mass emissions unit for which the optional low mass emissions excepted methodology in paragraph (c) of this section is being used in lieu of a continuous emission monitoring system or an excepted monitoring system under appendix D or E to this part.

Subpart C—[Amended]

19. Section 75.20 is amended by:

a. Revising the title of the section;

b. Revising the titles of paragraphs (a)(3), (a)(4), (c), (d), (g), (g)(1), (g)(2), (g)(4), and (g)(5);

c. Revising paragraphs (a) introductory text, (a)(1), (a)(3), (a)(4) introductory text, (a)(4)(i), (a)(4)(ii), (a)(4)(iii), (a)(5)(i), (b), (c) introductory text, (c)(1)(iii), (d)(1), (d)(2), (g) introductory text, (g)(1) introductory text, (g)(1)(i), (g)(2), (g)(4), and (g)(5);

d. Removing existing paragraph (c)(3);

e. Revising and redesignating existing paragraphs (c)(4), (c)(5), (c)(6), (c)(7), and (c)(8) as paragraphs (c)(3), (c)(4), (c)(8), (c)(9), and (c)(10), respectively; and revising newly designated paragraphs (c)(4) introductory text, (c)(8) introductory text, (c)(8)(i),

(c)(9)(ii), and (c)(10) introductory text; and

f. Adding new paragraphs (c)(5), (c)(6), (c)(7), (g)(6), (g)(7), (h), and (i), to read as follows:

§ 75.20 Initial certification and recertification procedures.

(a) *Initial certification approval process.* The owner or operator shall ensure that each continuous emission or opacity monitoring system required by this part, which includes the automated data acquisition and handling system, and, where applicable, the CO_2 continuous emission monitoring system, meets the initial certification requirements of this section and shall ensure that all applicable initial certification tests under paragraph (c) of this section are completed by the deadlines specified in § 75.4 and prior to use in the Acid Rain Program. In addition, whenever the owner or operator installs a continuous emission or opacity monitoring system in order to meet the requirements of §§ 75.13 through 75.18, where no continuous emission or opacity monitoring system was previously installed, initial certification is required.

(1) *Notification of initial certification test dates.* The owner or operator or designated representative shall submit a written notice of the dates of initial certification testing at the unit as specified in § 75.61(a)(1).

* * * * *

(3) *Provisional approval of certification (or recertification) applications.* Upon the successful completion of the required certification (or recertification) procedures of this section for each continuous emission or opacity monitoring system or component thereof, each continuous emission or opacity monitoring system or component thereof shall be deemed provisionally certified (or recertified) for use under the Acid Rain Program for a period not to exceed 120 days following receipt by the Administrator of the complete certification (or recertification) application under paragraph (a)(4) of this section, provided that no continuous emission or opacity monitor systems for a combustion source seeking to enter the Opt-in Program in accordance with part 74 of this chapter shall be deemed provisionally certified (or recertified) for use under the Acid Rain Program. Data measured and recorded by a provisionally certified (or recertified) continuous emission or opacity monitoring system or component thereof, in accordance with the requirements of appendix B to this part, will be considered valid quality-assured data (retroactive to the date and time of provisional certification or recertification)), provided that the Administrator does not invalidate the provisional certification (or recertification) by issuing a notice of disapproval within 120 days of receipt by the Administrator of the complete certification (or recertification) application. Note that if the data validation procedures of paragraph (b)(3) of this section are applied to the initial certification (or recertification) of a continuous emissions monitoring system, it is possible for data recorded by the CEMS during the certification (or recertification) test period to be quality assured retrospectively, upon completion of all of the certification (or recertification) tests. Therefore, in certain instances, the date and time of provisional certification (or recertification) of the CEMS may be earlier than the date and time of completion of the required certification (or recertification) tests.

(4) *Certification (or recertification) application formal approval process.* The Administrator will issue a notice of approval or disapproval of the certification (or recertification) application to the owner or operator within 120 days of receipt of the complete certification (or recertification) application. In the event the Administrator does not issue such a written notice within 120 days of receipt, each continuous emission or opacity monitoring system which meets the performance requirements of this part and is included in the certification (or recertification) application will be deemed certified (or recertified) for use under the Acid Rain Program.

(i) *Approval notice.* If the certification (or recertification) application is complete and shows that each continuous emission or opacity monitoring system meets the performance requirements of this part, then the Administrator will issue a written notice of approval of the certification (or recertification) application within 120 days of receipt.

(ii) *Incomplete application notice.* A certification (or recertification) application will be considered complete when all of the applicable information required to be submitted in § 75.63 has been received by the Administrator, the EPA Regional Office, and the appropriate State and/or local air pollution control agency. If the certification (or recertification) application is not complete, then the Administrator will issue a written notice of incompleteness that provides a reasonable timeframe for the designated representative to submit the additional information required to complete the certification (or recertification) application. If the designated representative has not complied with the notice of incompleteness by a specified due date, then the Administrator may issue a notice of disapproval specified under paragraph (a)(4)(iii) of this section. The 120-day review period shall not begin prior to receipt of a complete application.

(iii) *Disapproval notice.* If the certification (or recertification) application shows that any continuous emission or opacity monitoring system or component thereof does not meet the performance requirements of this part, or if the certification (or recertification) application is incomplete and the requirement for disapproval under paragraph (a)(4)(ii) of this section has been met, the Administrator shall issue a written notice of disapproval of the certification (or recertification) application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification (or recertification) is invalidated by the Administrator, and the data measured and recorded by each uncertified continuous emission or opacity monitoring system or component thereof shall not be considered valid quality-assured data beginning with the following time: from the hour of the probationary calibration error test that began the initial certification (or recertification) test period, if the data validation procedures of paragraph (b)(3) of this section were used to retrospectively validate data; or from the date and time of completion of the invalid certification tests until the date and time that the owner or operator completes subsequently approved initial certification tests, if the data validation procedures of paragraph (b)(3) of this section were not used. The owner or operator shall follow the procedures for loss of initial certification in paragraph (a)(5) of this section for each continuous emission or opacity monitoring system or component thereof which is disapproved for initial certification. For each disapproved recertification, the owner or operator shall follow the procedures of paragraph (b)(5) of this section.

* * * * *

(5) * * *

(i) Until such time, date, and hour as the continuous emission monitoring system or component thereof can be adjusted, repaired, or replaced and certification tests successfully completed, the owner or operator shall substitute the following values, as applicable, for each hour of unit operation during the period of invalid

data specified in paragraph (a)(4)(iii) of this section or in § 75.21: the maximum potential concentration of SO_2 as defined in section 2.1.1.1 of appendix A to this part to report SO_2 concentration; the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter to report NO_X emissions; the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part to report volumetric flow; or the maximum potential concentration of CO_2, as defined in section 2.1.3.1 of appendix A to this part to report CO_2 concentration data; and

* * * * *

(b) *Recertification approval process.* Whenever the owner or operator makes a replacement, modification, or change in a certified continuous emission monitoring system or continuous opacity monitoring system that is determined by the Administrator to significantly affect the ability of the system to accurately measure or record the SO_2 or CO_2 concentration, stack gas volumetric flow rate, NO_X emission rate, or opacity, or to meet the requirements of § 75.21 or appendix B to this part, the owner or operator shall recertify the continuous emission monitoring system or continuous opacity monitoring system, according to the procedures in this paragraph. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit operation that is determined by the Administrator to significantly change the flow or concentration profile, the owner or operator shall recertify the monitoring system according to the procedures in this paragraph. Examples of changes which require recertification include: replacement of the analyzer; change in location or orientation of the sampling probe or site; changing of flow rate monitor polynomial coefficients; and complete replacement of an existing continuous emission monitoring system or continuous opacity monitoring system. The owner or operator shall recertify a continuous opacity monitoring system whenever the monitor path length changes or as required by an applicable State or local regulation or permit. Any change to a stack flow rate or gas monitoring system for which the Administrator determines that a RATA is not necessary shall not be considered a recertification event. In such cases, any other tests that the Administrator determines to be necessary (linearity checks, calibration error tests, DAHS verifications, etc.) shall be performed as diagnostic tests, rather than recertification tests. The data validation procedures in paragraph (b)(3) of this section shall be applied to linearity checks, 7-day calibration error tests, and cycle time tests when these are required as diagnostic tests. When the data validation procedures of paragraph (b)(3) of this section are applied in this manner, replace the word ''recertification'' with the word ''diagnostic.''

(1) *Tests required.* For recertification testing after changing the flow rate monitor polynomial coefficients, the owner or operator shall complete a 3-level RATA. For all other recertification testing, the owner or operator shall complete all initial certification tests in paragraph (c) of this section that are applicable to the monitoring system, except as otherwise approved by the Administrator.

(2) *Notification of recertification test dates.* The owner, operator, or designated representative shall submit notice of testing dates for recertification under this paragraph as specified in § 75.61(a)(1)(ii), unless all of the tests in paragraph (c) of this section are required for recertification, in which case the owner or operator shall provide notice in accordance with the notice provisions for initial certification testing in § 75.61(a)(1)(i).

(3) *Recertification test period requirements and data validation.* (i) In the period extending from the hour of the replacement, modification or change made to a monitoring system that triggers the need to perform recertification test(s) of the CEMS to the hour of successful completion of a probationary calibration error test (according to paragraph (b)(3)(ii) of this section) following the replacement, modification, or change to the CEMS, the owner or operator shall either substitute for missing data, according to the standard missing data procedures in §§ 75.33 through 75.37, or report emission data using a reference method or another monitoring system that has been certified or approved for use under this part.

(ii) Once the modification or change to the CEMS has been completed and all of the associated repairs, component replacements, adjustments, linearization, and reprogramming of the CEMS have been completed, a probationary calibration error test is required to establish the beginning point of the recertification test period. In this instance, the first successful calibration error test of the monitoring system following completion of all necessary repairs, component replacements, adjustments, reprogramming, and any preliminary tests (e.g., trial RATA runs or a challenge of the monitor with calibration gases other than those used to perform the daily calibration error test) shall be the probationary calibration error test. The probationary calibration error test must be passed before any of the required recertification tests are commenced.

(iii) Beginning with the hour of commencement of a recertification test period, emission data recorded by the CEMS are considered to be conditionally valid, contingent upon the results of the subsequent recertification tests.

(iv) Each required recertification test shall be completed no later than the following number of unit operating hours after the probationary calibration error test that initiates the test period:

(A) For a linearity test and/or cycle time test, 168 consecutive unit operating hours;

(B) For a RATA (whether normal-load or multiple-load), 720 consecutive unit operating hours; and

(C) For a 7-day calibration error test, 21 consecutive unit operating days.

(v) All recertification tests shall be performed hands-off, as follows. No adjustments to the calibration of the CEMS, other than the adjustments described in section 2.1.3 of appendix B to this part, are permitted prior to or during the recertification test period. Routine daily calibration error tests shall be performed throughout the recertification test period, in accordance with section 2.1.1 of appendix B to this part. The additional calibration error test requirements in section 2.1.3 of appendix B to this part shall also apply during the recertification test period.

(vi) If all of the required recertification tests and required daily calibration error tests are successfully completed in succession with no failures, and if each recertification test is completed within the time period specified in paragraph (b)(3)(iv)(A), (B), or (C) of this section, then all of the conditionally valid emission data recorded by the CEMS shall be considered quality assured, from the hour of commencement of the recertification test period until the hour of completion of the required test(s).

(vii) If a required recertification test is failed or aborted due to a problem with the CEMS, or if a calibration error test is failed during a recertification test period, data validation shall be done as follows:

(A) If any required recertification test is failed, it shall be repeated. If any recertification test other than a 7-day calibration error test is failed or aborted due to a problem with the CEMS, the original recertification test period is ended, and a new recertification test period must be commenced with a

probationary calibration error test. The tests that are required in this new recertification test period will include any tests that were required for the initial recertification event which were not successfully completed and any recertification or diagnostic tests that are required as a result of changes made to the monitoring system to correct the problems that caused the failure of the recertification test. The new recertification test sequence shall not be commenced until all necessary maintenance activities, adjustments, linearizations, and reprogramming of the CEMS have been completed;

(B) If a linearity test, RATA, or cycle time test is failed or aborted due to a problem with the CEMS, all conditionally valid emission data recorded by the CEMS are invalidated, from the hour of commencement of the recertification test period to the hour in which the test is failed or aborted. Data from the CEMS remain invalid until the hour in which a new recertification test period is commenced, following corrective action, and a probationary calibration error test is passed, at which time the conditionally valid status of emission data from the CEMS begins;

(C) If a 7-day calibration error test is failed within the recertification test period, previously-recorded conditionally valid emission data from the CEMS are not invalidated, provided that the calibration error on the day of the failed 7-day calibration error test does not exceed twice the performance specification in section 3 of appendix A to this part; and

(D) If a calibration error test is failed (i.e., the results of the test exceed twice the performance specification in section 3 of appendix A to this part) during a recertification test period, the CEMS is out-of-control as of the hour in which the calibration error test is failed. Emission data from the CEMS shall be invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test following corrective action, at which time the conditionally valid status of data from the monitoring system resumes. Failure to perform a required daily calibration error test during a recertification test period shall also cause data from the CEMS to be invalidated prospectively, from the hour in which the calibration error test was due until the hour of completion of a subsequent successful calibration error test. Previously-passed recertification tests in the sequence and previously-recorded conditionally valid data shall not be affected by a late calibration error test. Whenever a calibration error test is failed or missed during a recertification test period, no further recertification tests shall be performed until the required subsequent calibration error has been passed, re-establishing the conditionally valid status of data from the monitoring system.

(viii) If any required recertification test is not completed within its allotted time period, data validation shall be done as follows. For a late linearity test, RATA, or cycle time test that is passed on the first attempt, data from the monitoring system shall be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. For a late 7-day calibration error test, whether or not it is passed on the first attempt, data from the monitoring system shall also be invalidated from the hour of expiration of the recertification test period until the hour of completion of the late test. For a late linearity test, RATA, or cycle time test that is failed on the first attempt or aborted on the first attempt due to a problem with the monitor, all conditionally valid data from the monitoring system shall be considered invalid back to the hour of the first probationary calibration error test which initiated the recertification test period. Data from the monitoring system shall remain invalid until the hour of successful completion of the late recertification test and any additional recertification or diagnostic tests that are required as a result of changes made to the monitoring system to correct problems that caused failure of the late recertification test.

(ix) If any required recertification test of a monitoring system has not been completed by the end of a calendar quarter and if data contained in the quarterly report is conditionally valid pending the results of test(s) to be completed in a subsequent quarter, the owner or operator shall indicate this by means of a suitable conditional data flag in the electronic quarterly report for that quarter. The owner or operator shall resubmit the report for that quarter if the required recertification test is subsequently failed. In the resubmitted report, the owner or operator shall use the appropriate missing data routine in § 75.31 or § 75.33 to replace with substitute data each hour of conditionally valid data that was invalidated by the failed recertification test. In addition, if the owner or operator submits any conditionally valid data (as defined in § 72.2 of this chapter) in any of the four quarterly reports for a given year, the owner or operator shall indicate the status of the conditionally valid data (i.e., resolved or unresolved) in the annual compliance certification report required under § 72.90 of this chapter for that year. Alternatively, if any required recertification test is not completed by the end of a particular calendar quarter but is completed no later than 30 days after the end of that quarter (i.e., prior to the deadline for submitting the quarterly report under § 75.64), the test data and results may be submitted with the earlier quarterly report even though the test date(s) are from the next calendar quarter. In such instances, if the recertification test(s) are passed in accordance with the provisions of paragraph (b)(3) of this section, conditionally valid data may be reported as quality-assured, in lieu of reporting a conditional data flag. If the recertification test(s) is failed and if conditionally valid data are replaced, as appropriate, with substitute data, then neither the reporting of a conditional data flag nor resubmission is required.

(x) If the replacement, modification, or change requiring recertification of the CEMS is such that the data collected by the prior certified monitoring system are no longer representative, such as after a change to the flue gas handling system or unit operation that requires changing the span value to be consistent with section 2.1 of appendix A to this part, the owner or operator shall substitute for missing data as follows, in the period extending from the hour of commencement of the replacement, modification, or change requiring recertification of the CEMS to the hour of commencement of the recertification test period:

(A) For a change that results in a significantly higher concentration or flow rate, substitute maximum potential values according to the procedures in paragraph (a)(5) of this section; or

(B) For a change that results in a significantly lower concentration or flow rate, substitute data using the standard missing data procedures.

(C) The owner or operator shall then use the initial missing data procedures in § 75.31, beginning with the first hour of quality assured data obtained with the recertified monitoring system, unless otherwise provided by § 75.34 for units with add-on emission controls.

(4) *Recertification application.* The designated representative shall apply for recertification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The owner or operator shall submit the recertification application in accordance with § 75.60, and each complete recertification application shall include the information specified in § 75.63.

(5) *Approval or disapproval of request for recertification.* The procedures for

provisional certification in paragraph (a)(3) of this section shall apply to recertification applications. The Administrator will issue a written notice of approval or disapproval according to the procedures in paragraph (a)(4) of this section. In the event that a recertification application is disapproved, data from the monitoring system are invalidated and the applicable missing data procedures in § 75.31 or § 75.33 shall be used from the date and hour of receipt of such notice back to the hour of the probationary calibration error test that began the recertification test period. Data from the monitoring system remain invalid until a subsequent probationary calibration error test is passed, beginning a new recertification test period. The owner or operator shall repeat all recertification tests or other requirements, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval. The designated representative shall submit a notification of the recertification retest dates, as specified in § 75.61(a)(1)(ii), and shall submit a new recertification application according to the procedures in paragraph (b)(4) of this section.

(c) *Initial certification and recertification procedures.* Prior to the deadline in § 75.4, the owner or operator shall conduct initial certification tests and in accordance with § 75.63, the designated representative shall submit an application to demonstrate that the continuous emission or opacity monitoring system and components thereof meet the specifications in appendix A to this part. The owner or operator shall compare reference method values with output from the automated data acquisition and handling system that is part of the continuous emission monitoring system being tested. Except as specified in paragraphs (b)(1), (d), and (e) of this section, the owner or operator shall perform the following tests for initial certification or recertification of continuous emission or opacity monitoring systems or components according to the requirements of appendix A to this part:

(1) * * *

(iii) A relative accuracy test audit. For the NO_X-diluent system, the RATA shall be done on a system basis, in units of lb/mmBtu.

* * * * *

(3) The initial certification test data from an O_2-or a CO_2-diluent gas monitor certified for use in a NO_X continuous emission monitoring system may be submitted to meet the requirements of paragraph (c)(4) of this section. Also, for a diluent monitor that is used both as a CO_2 monitoring system and to determine heat input, only one set of diluent monitor certification data need be submitted (under the component and system identification numbers of the CO_2 monitoring system).

(4) For each CO_2 pollutant concentration monitor, each O_2 monitor which is part of a CO_2 continuous emission monitoring system, each diluent monitor used to monitor heat input and each SO_2-diluent continuous emission monitoring system:

* * * * *

(5) For each continuous moisture monitoring system consisting of wet-and dry-basis O_2 analyzers:

(i) A 7-day calibration error test of each O_2 analyzer;

(ii) A cycle time test of each O_2 analyzer;

(iii) A linearity test of each O_2 analyzer; and

(iv) A RATA, directly comparing the percent moisture measured by the monitor to a reference method.

(6) For each continuous moisture sensor:

(i) A 7-day calibration error test; and

(ii) A RATA, directly comparing the percent moisture measured by the monitor sensor to a reference method.

(7) For a continuous moisture monitoring system consisting of a temperature sensor and a data acquisition and handling system (DAHS) software component programmed with a moisture lookup table:

(i) A demonstration that the correct moisture value for each hour is being taken from the moisture lookup tables and applied to the emission calculations. At a minimum, the demonstration shall be made at three different temperatures covering the normal range of stack temperatures.

(ii) [Reserved]

(8) The owner or operator shall ensure that initial certification or recertification of a continuous opacity monitor for use under the Acid Rain Program is conducted according to one of the following procedures:

(i) Performance of the tests for initial certification or recertification, according to the requirements of Performance Specification 1 in appendix B to part 60 of this chapter; or

* * * * *

(9) * * *

(ii) Proper computation and application of the missing data substitution procedures in subpart D of this part and the bias adjustment factors in section 7 of appendix A to this part.

(10) The owner or operator shall provide, or cause to be provided, adequate facilities for initial certification or recertification testing that include:

* * * * *

(d) *Initial certification and recertification and quality assurance procedures for optional backup continuous emission monitoring systems.*

(1) *Redundant backups.* The owner or operator of an optional redundant backup continuous emission monitoring system shall comply with all the requirements for initial certification and recertification according to the procedures specified in paragraphs (a), (b), and (c) of this section. The owner or operator shall operate the redundant backup continuous emission monitoring system during all periods of unit operation, except for periods of calibration, quality assurance, maintenance, or repair. The owner or operator shall perform upon the redundant backup continuous emission monitoring system all quality assurance and quality control procedures specified in appendix B to this part, except that the daily assessments in section 2.1 of appendix B to this part are optional for days on which the redundant backup monitoring system is not used to report emission data under this part. For any day on which a redundant backup monitoring system is used to report emission data, the system must meet all of the applicable daily assessment criteria in appendix B to this part.

(2) *Non-redundant backups.* The owner or operator of an optional non-redundant backup continuous emission monitoring system shall comply with all of the following requirements for initial certification, quality assurance, recertification, and data reporting:

(i) For a non-redundant backup gas monitoring system that has its own separate probe, sample interface, and analyzer or for a non-redundant backup flow monitor, all of the tests in paragraph (c) of this section are required for initial certification of the system, except for the 7-day calibration error test.

(ii) For a non-redundant backup gas monitoring system consisting of one or more like-kind replacement analyzers that use the same probe and sample interface as a primary monitoring system, no initial certification of the non-redundant backup monitoring system is required. Note that a non-redundant backup analyzer, connected to the same probe and interface as a primary analyzer in order to satisfy the dual span requirements of section

2.1.1.4 or 2.1.2.4 of appendix A to this part, shall be considered a like-kind, non-redundant backup analyzer.

(iii) Each non-redundant backup monitoring system shall comply with the daily and quarterly quality assurance and quality control requirements in appendix B to this part for each day and quarter that the non-redundant backup monitoring system is used to report data, except that the requirements for when a linearity test must be performed are superseded by the requirements of this section. The owner or operator shall ensure that each non-redundant backup continuous emission monitoring system passes a linearity check (for pollutant concentration and diluent gas monitors) or a calibration error test (for flow monitors) prior to each use for recording and reporting emissions. For a non-redundant backup NO_X-diluent or SO_2-diluent monitoring system consisting of a primary pollutant analyzer and a like-kind replacement diluent analyzer (or vice-versa), provided that the primary analyzer is operating and is not out-of-control with respect to any of its quality assurance requirements, only the like-kind replacement analyzer must pass a linearity check before the system is used for data reporting. When a non-redundant backup monitoring system is brought into service prior to conducting the linearity test, a probationary calibration error test (as described in paragraph (b)(3)(ii) of this section), which will begin a period of conditionally valid data, may be performed in order to allow the use of data retrospectively, as follows. Conditionally valid data from the CEMS are validated back to the hour of completion of the probationary calibration error test if the following conditions are met: if no adjustments are made to the monitor other than those specified in section 2.1.3 of appendix B to this part between the probationary calibration error test and the successful completion of the linearity test, and if the linearity test is passed within 168 unit operating hours of the probationary calibration error test. However, if the linearity test is either failed, aborted due to a problem with the CEMS, or not completed as required, then all of the conditionally valid data are invalidated back to the hour of the probationary calibration error test, and data from the CEMS remain invalid until the hour of completion of a successful linearity test.

(iv) When data are reported from a non-redundant backup monitoring system, the appropriate bias adjustment factor (BAF) shall be determined as follows:

(A) Apply the BAF from the most recent RATA of the non-redundant backup system (even if that RATA was done more than 12 months previously); or

(B) If no RATA results are available for the non-redundant backup system (e.g., for a non-redundant backup gas monitoring system that uses the same probe and sample interface as the primary monitoring system), apply the primary monitoring system BAF.

(v) A non-redundant backup system may not be used for reporting data from a particular affected unit or common stack for more than 720 hours in any one calendar year, unless the monitoring system passes a RATA at that same unit or stack.

(vi) For each non-redundant backup gas monitoring system that has its own separate probe, sample interface, and analyzer and for each non-redundant backup flow monitor, no more than eight successive calendar quarters shall elapse following the quarter in which the last RATA of the monitoring system was done at a particular unit or stack, without performing a subsequent RATA. Otherwise, the monitoring system may not be used to report data from that unit or stack until the hour of completion of a successful RATA at that location.

* * * * *

(g) *Initial certification and recertification procedures for excepted monitoring systems under appendices D and E.* The owner or operator of a gas-fired unit, oil-fired unit, or diesel-fired unit using the optional protocol under appendix D or E to this part shall ensure that an excepted monitoring system under appendix D or E to this part meets the applicable general operating requirements of § 75.10, the applicable requirements of appendices D and E to this part, and the initial certification or recertification requirements of this paragraph.

(1) *Initial certification and recertification testing.* The owner or operator shall use the following procedures for initial certification and recertification of an excepted monitoring system under appendix D or E to this part.

(i) When the optional SO_2 mass emissions estimation procedure in appendix D to this part or the optional NO_X emissions estimation protocol in appendix E to this part is used, the owner or operator shall provide data from a flowmeter accuracy test (or shall provide a statement of calibration if the flowmeter meets the accuracy standard by design) for each fuel flowmeter, according to the appropriate calibration procedures using one of the following standard methods: ASME MFC–3M–1989 with September 1990 Errata, ''Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi''; ASME MFC–4M–1986 (Reaffirmed 1990) ''Measurement of Gas Flow by Turbine Meters''; ASME MFC–5M–1985, ''Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters''; ASME MFC–6M–1987 with June 1987 Errata, ''Measurement of Fluid Flow in Pipes Using Vortex Flow Meters''; ASME MFC–7M–1987 (Reaffirmed 1992), ''Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles''; ASME MFC–9M–1988 with December 1989 Errata, ''Measurement of Liquid Flow in Closed Conduits by Weighing Method''; ISO 8316: 1987(E) ''Measurement of Liquid Flow in Closed Conduits—Method by Collection of the Liquid in a Volumetric Tank''; Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (1985 Edition); American Gas Association Report No. 3: Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines (October 1990 Edition), Part 2: Specification and Installation Requirements (February 1991 Edition), and Part 3: Natural Gas Applications (August 1992 Edition), excluding the modified calculation procedures of Part 3; or American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993), as required by appendices D and E to this part (all methods incorporated by reference under § 75.6).

* * * * *

(2) *Initial certification and recertification testing notification.* The designated representative shall provide initial certification testing notification and periodic retesting notification for an excepted monitoring system under appendix E to this part as specified in § 75.61. The designated representative shall submit recertification testing notification, as specified in § 75.61, for quality assurance related NO_X emission rate testing under section 2.3 of appendix E to this part for an excepted monitoring system under appendix E to this part. Initial certification testing notification or periodic retesting notification is not required for testing of a fuel flowmeter or for testing of an excepted monitoring system under appendix D to this part.

* * * * *

(4) *Initial certification or recertification application.* The designated representative shall submit an initial certification or recertification application in accordance with §§ 75.60 and 75.63.

(5) *Provisional approval of initial certification and recertification applications.* Upon the successful completion of the required initial certification or recertification procedures for each excepted monitoring system under appendix D or E to this part, each excepted monitoring system under appendix D or E to this part shall be deemed provisionally certified for use under the Acid Rain Program during the period for the Administrator's review. The provisions for the initial certification or recertification application formal approval process in paragraph (a)(4) of this section shall apply, except that ''continuous emission or opacity monitoring system'' shall be replaced with ''excepted monitoring system'' and except that ''shall follow the procedures for loss of initial certification in paragraph (a)(5)'' or ''shall follow the procedures of paragraph (b)(5)'' shall be replaced with ''shall follow the procedures for loss of certification in paragraph (g)(7)''. Data measured and recorded by a provisionally certified excepted monitoring system under appendix D or E to this part will be considered quality assured data from the date and time of completion of the last initial certification or recertification test, provided that the Administrator does not revoke the provisional certification by issuing a notice of disapproval in accordance with the provisions in paragraph (a)(4) or (b)(5) of this section.

(6) *Recertification requirements.* Recertification of an excepted monitoring system under appendix D or E to this part is required for any modification to the system or change in operation that could significantly affect the ability of the system to accurately account for emissions and for which the Administrator determines that an accuracy test of the fuel flowmeter or a retest under appendix E to this part to re-establish the NO_X correlation curve is required. Examples of such changes or modifications include fuel flowmeter replacement, changes in unit configuration, or exceedance of operating parameters.

(7) *Procedures for loss of certification or recertification for excepted monitoring systems under appendices D and E to this part.* In the event that a certification or recertification application is disapproved for an excepted monitoring system, data from the monitoring system are invalidated, and the applicable missing data procedures in section 2.4 of appendix D or section 2.5 of appendix E to this part shall be used from the date and hour of receipt of such notice back to the hour of the provisional certification. Data from the excepted monitoring system remain invalid until all required tests are repeated and the excepted monitoring system is again provisionally certified. The owner or operator shall repeat all certification or recertification tests or other requirements, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval. The designated representative shall submit a notification of the certification or recertification retest dates if required under paragraph (g)(2) of this section and shall submit a new certification or recertification application according to the procedures in paragraph (g)(4) of this section.

(h) *Initial certification and recertification procedures for low mass emission units using the excepted methodologies under § 75.19.* The owner or operator of a gas-fired, oil-fired, or diesel-fired unit using the optional low mass emissions excepted methodologies under § 75.19 shall meet the applicable general operating requirements of § 75.10, the applicable requirements of § 75.19, and the applicable certification requirements of this paragraph (h).

(1) *Monitoring plan.* The designated representative shall submit a monitoring plan in accordance with §§ 75.53 and 75.62.

(2) *Certification application.* The designated representative shall submit a certification application in accordance with § 75.63(a)(1)(iii).

(3) *Approval of certification applications.* Upon submission of the required certification application for approval to use the low mass emissions excepted methodology under § 75.19, the excepted methodology shall be deemed provisionally certified for use under the Acid Rain Program during the period for the Administrator's review. The provisions for the certification application formal approval process in the introductory text of paragraph (a)(4) and in paragraphs (a)(4)(i), (ii), and (iv) of this section shall apply, except that ''continuous emission or opacity monitoring system'' shall be replaced with ''excepted methodology.''

(4) *Disapproval of certification applications.* If the Administrator determines that the certification application does not demonstrate that the unit meets the requirements of §§ 75.19(a) and (b), the Administrator shall issue a written notice of disapproval of the certification application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification is invalidated by the Administrator, and the data recorded under the excepted methodology shall not be considered valid. The owner or operator shall follow the procedures for loss of certification:

(i) The owner or operator shall substitute the following values, as applicable, for each hour of unit operation during the period of invalid data specified in paragraph (a)(4)(iii) of this section or in §§ 75.21(e) (introductory paragraph) and 75.21(e)(1): the maximum potential concentration of SO_2, as defined in section 2.1 of appendix A to this part to report SO_2 concentration; the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter to report NO_X emissions; the maximum potential flow rate, as defined in section 2.1 of appendix A to this part to report volumetric flow; or the maximum CO_2 concentration used to determine the maximum potential concentration of SO_2 in section 2.1.1.1 of appendix A to this part to report CO_2 concentration data until such time, date, and hour as a continuous emission monitoring system or excepted monitoring system, where applicable, is installed and provisionally certified;

(ii) The designated representative shall submit a notification of certification test dates, as specified in § 75.61(a)(1)(ii), and a new certification application according to the procedures in paragraph (a)(2) of this section; and

(iii) The owner or operator shall install and provisionally certify continuous emission monitoring systems or excepted monitoring systems, where applicable, no later than 180 unit operating days after the date of issuance of the notice of disapproval.

(i) *Initial certification and recertification procedures for excepted flow monitoring systems under appendix I.* The owner or operator of a gas-fired unit, oil-fired unit, or diesel-fired unit using the optional protocol under appendix I to this part shall ensure that an excepted flow monitoring system under appendix I to this part meets the applicable general operating requirements of § 75.10, the applicable requirements of appendix I to this part, and the initial certification and recertification requirements of this paragraph.

(1) *Initial certification and recertification testing.* The owner or operator shall, where applicable, use the

following procedures for certification and recertification of an excepted flow monitoring system under appendix I to this part.

(i) For an excepted flow monitoring system under appendix I to this part where each component is tested separately, perform the following tests on each O_2 or CO_2 component monitor:

(A) 7-day calibration error test;

(B) Linearity check;

(C) Cycle time test;

(D) Relative accuracy test audit using Test Method 3A from appendix A to part 60 of this chapter; and

(E) Bias test.

(ii) For an excepted flow monitoring system under appendix I to this part where each component is tested separately, meet the certification procedures under paragraph (g)(1)(i) of this section and the recertification procedures under paragraph (g)(6) of this section on each fuel flowmeter component using the standards specified, or meet the testing procedure under section 2.1.5.2 of appendix D to this part.

(iii) For an excepted flow monitoring system under appendix I to this part that is tested as an entire system, perform the following tests:

(A) 7-day calibration error test on the O_2 or CO_2 monitor,

(B) Linearity check on the O_2 or CO_2 monitor,

(C) Cycle time test on the O_2 or CO_2 monitor,

(D) Relative accuracy test audit on the entire excepted flow monitoring system under appendix I to this part, using Test Method 2 (or its allowable alternatives) from appendix A to part 60 of this chapter, and

(E) Bias test on the entire excepted flow monitoring system under appendix I to this part.

(iv) For the automated data acquisition and handling system used as part of an excepted flow monitoring system under appendix I to this part, the owner or operator shall perform tests designed to verify:

(A) The proper computation of hourly averages for volumetric flow rates, heat input, and pollutant mass emissions; and

(B) The proper computation and application of the missing data substitution procedures for volumetric flow in subpart D of this part.

(2) *Initial certification and recertification testing notification.* The designated representative shall provide initial certification and recertification testing notification for an excepted flow monitoring system under appendix I to this part, as specified in § 75.61, for any relative accuracy test audit.

(3) *Monitoring plan.* The designated representative shall submit a monitoring plan in accordance with §§ 75.53 and 75.62. For a unit that previously had a flow monitoring system or an excepted monitoring system under appendix D to this part and later submits a revised monitoring plan for an excepted flow monitoring system under appendix I to this part, the designated representative shall submit the revised monitoring plan no later than 45 days prior to the first day of certification testing.

(4) *Certification or recertification application.* The designated representative shall submit an initial certification or recertification application in accordance with §§ 75.60 and 75.63.

(5) *Approval of initial certification and recertification applications.* Upon successful completion of the required initial certification or recertification procedures for each excepted monitoring system under appendix I to this part, each excepted monitoring system under appendix I to this part shall be deemed provisionally certified for use under the Acid Rain Program during the period for the Administrator's review. The provisions for the initial certification (or recertification) application formal approval process in paragraph (a)(4) of this section shall apply, except that ''continuous emission or opacity monitoring system'' shall be replaced with ''excepted monitoring system'' and except that ''shall follow the procedures for loss of initial certification in paragraph (a)(5)'' or ''shall follow the procedures of paragraph (b)(5)'' shall be replaced with ''shall follow the procedures for loss of certification in paragraph (i)(7)''. Data measured and recorded by a provisionally certified excepted monitoring system under appendix I to this part will be considered quality assured data from the date and time of completion of the final certification test, provided that the Administrator does not revoke the provisional certification by issuing a notice of disapproval within 120 days of receipt of the complete initial certification or recertification application in accordance with the provisions in paragraph (a)(4) of this section.

(6) *Recertification requirements.* A recertification of an excepted flow monitoring system under appendix I to this part is required for any modification to the equipment used in the appendix I excepted flow monitoring system that would require recertification under paragraph (b) or (g) of this section.

(7) *Procedures for loss of certification for excepted monitoring systems under appendix I to this part.* In the event that a certification or recertification application is disapproved for an excepted monitoring system under appendix I to this part, data from the monitoring system are invalidated, and the applicable missing data procedures in section 4 of appendix I to this part shall be used from the date and hour of receipt of such notice back to the hour of the provisional certification. Data from the excepted monitoring system remain invalid until all required tests are repeated and the excepted monitoring system is again provisionally certified. The owner or operator shall repeat all certification or recertification tests or other requirements, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval. The designated representative shall submit a notification of the certification or recertification retest dates, if required under paragraph (i)(2) of this section, and shall submit a new certification or recertification application according to the procedures in paragraph (i)(4) of this section.

20. Section 75.21 is amended by:

a. Revising paragraphs (a)(2), (a)(4), (a)(5), (a)(6) and (e);

b. Redesignating existing paragraphs (a)(7) and (a)(8) as paragraphs (a)(9) and (a)(10), respectively; revising newly designated paragraph (a)(9); and

c. Adding new paragraphs (a)(7), (a)(8), and (f), to read as follows:

§ 75.21 Quality assurance and quality control requirements.

(a) * * *

(2) The owner or operator shall ensure that each non-redundant backup continuous emission monitoring system meets the quality assurance requirements of § 75.20(d) for each day and quarter that the system is used to report data.

* * * * *

(4) When a unit combusts only natural gas or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas and SO_2 emissions are determined in accordance with § 75.11(e)(3), the owner or operator of a unit with an SO_2 continuous emission monitoring system is not required to perform the daily or quarterly assessments of the SO_2 monitoring system under appendix B to this part on any day or in any calendar quarter in which only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content

of natural gas) is combusted in the unit. Notwithstanding, the results of any daily calibration error test and linearity test of the SO_2 monitoring system performed while the unit is combusting only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) shall be considered valid. If any such test is failed, the SO_2 monitoring system shall be considered to be out-of-control. The length of the out-of-control period shall be determined in accordance with the applicable procedures in section 2.1.4 or 2.2.3 of appendix B to this part.

(5) For a unit with an SO_2 continuous monitoring system, in which natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) is sometimes burned as a primary and/or backup fuel and in which higher-sulfur fuel(s) such as oil or coal are, at other times, burned as primary or backup fuel(s), the owner shall perform the relative accuracy test audits of the SO_2 monitoring system (as required by section 6.5 of appendix A to this part and section 2.3.1 of appendix B to this part) only when the higher-sulfur fuel is combusted in the unit and shall not perform SO_2 relative accuracy test audits when gaseous fuel is the only fuel being combusted.

(6) If the designated representative certifies that a unit with an SO_2 monitoring system burns only fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas, the SO_2 monitoring system is exempted from the relative accuracy test audit requirements in appendices A and B to this part. For the purposes of this part, a fuel having a total sulfur content no greater than 0.05 percent sulfur by weight shall be deemed to qualify as a ''fuel with a total sulfur content no greater than the total sulfur content of natural gas.''

(7) If the designated representative certifies that a particular unit with an SO_2 monitoring system combusts fuel(s) with a total sulfur content greater than the total sulfur content of natural gas (i.e., >0.05 percent sulfur by weight) only as emergency backup fuel(s) or for short-term testing, the SO_2 monitoring system shall be conditionally exempted from the RATA requirements of appendices A and B to this part, provided that the unit combusts the higher-sulfur fuel(s) for no more than 480 hours per calendar year. If, in a particular calendar year, the higher-sulfur fuel usage exceeds 480 hours, a RATA of the SO_2 monitor shall be performed (while combusting the higher-sulfur fuel) either by the end of the calendar quarter in which the exceedance occurs or by the end of a 720 unit operating hour grace period following the quarter in which the exceedance occurs (see SO_2 RATA provisions in section 2.3.3 of appendix B to this part for further discussion of the grace period).

(8) On and after January 1, 2000, the quality assurance provisions of §§ 75.11(e)(3)(i) through 75.11(e)(3)(iv) shall apply (except that the term ''gaseous fuel'' shall be replaced with ''fuel'') to all units with SO_2 monitoring systems during hours in which only fuel having a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤0.05 percent sulfur by weight) is combusted in the unit, except for units that use such fuel only for unit startup.

(9) Provided that a unit with an SO_2 monitoring system is not exempted under paragraph (a)(6) or (a)(7) of this section from the SO_2 RATA requirements of this part, any calendar quarter during which a unit combusts only fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas (i.e. ≤0.05 percent sulfur by weight) shall be excluded in determining the quarter in which the next relative accuracy test audit must be performed for the SO_2 monitoring system. However, no more than eight successive calendar quarters shall elapse after a relative accuracy test audit of an SO_2 monitoring system, without a subsequent relative accuracy test audit having been performed. The owner or operator shall ensure that a relative accuracy test audit is performed either by the end of the eighth successive elapsed calendar quarter since the last RATA or in the next calendar quarter in which a fuel with a total sulfur content greater than the total sulfur content of natural gas is burned in the unit.

* * * * *

(e) *Consequences of audits.* The owner or operator shall invalidate data from a continuous emission monitoring system or continuous opacity monitoring system upon failure of an audit under paragraph (a)(4)(iv) of § 75.20, an audit under appendix B to this part, or any other audit, beginning with the unit operating hour of completion of a failed audit as determined by the Administrator. The owner or operator shall not use invalidated data for reporting either emissions or heat input, nor for calculating monitor data availability.

(1) *Audit decertification.* Whenever both an audit of a continuous emission or opacity monitoring system (or component thereof, including the data acquisition and handling system), or an audit of any excepted monitoring system under appendix D, E, or I to this part, or of any alternative monitoring system under subpart E of this part, and a review of the initial certification application or of a recertification application, reveal that any system or component should not have been certified or recertified because it did not meet a particular performance specification or other requirement of this part, both at the time of the initial certification or recertification application submission and at the time of the audit, the Administrator will issue a notice of disapproval of the certification status of such system or component. For the purposes of this paragraph, an audit shall be either a field audit of the facility or an audit of any information submitted to EPA or the State agency regarding the facility. By issuing the notice of disapproval, the certification status is revoked, prospectively, by the Administrator. The data measured and recorded by each system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests. The owner or operator shall follow the procedures in § 75.20(a)(5) for initial certification or § 75.20(b)(5) for recertification to replace, prospectively, all of the invalid, non-quality-assured data for each disapproved system.

(2) *Out-of-control period.* Whenever a continuous emission monitoring system or continuous opacity monitoring system fails a quality assurance audit, an audit under § 75.20(a)(4)(iv), or another audit, the system is out-of-control. The owner or operator shall follow the procedures for out-of-control periods in § 75.24.

(f) *Excepted flow monitoring systems under appendix I.* The owner or operator of an affected unit shall operate, calibrate, and maintain each excepted flow monitoring system under appendix I to this part used under the Acid Rain Program according to the quality assurance and quality control procedures in appendices B and I to this part.

21. Section 75.22 is amended by revising paragraphs (a)(2), (a)(4), and (c)(1) introductory text to read as follows:

§ 75.22 Reference test methods.

(a) * * *

(2) Method 2 or its allowable alternatives, except for 2B and 2E, are the reference methods for determination of volumetric flow.

* * * * *

(4) Method 4 (either the standard procedure described in section 2 of the method or the moisture approximation procedure described in section 3 of the method) shall be used to correct pollutant concentrations from a dry basis to a wet basis (or from a wet basis to a dry basis) and shall be used when relative accuracy test audits of continuous moisture monitoring systems are conducted. For the purpose of determining the stack gas molecular weight, however, the alternative techniques for approximating the stack gas moisture content described in section 1.2 of Method 4 may be used in lieu of the procedures in sections 2 and 3 of the method.

* * * * *

(c) * * *

(1) Instrumental EPA Reference Methods 3A, 6C, 7E, and 20 shall be conducted using calibration gases as defined in section 5 of appendix A to this part. Otherwise, performance tests shall be conducted and data reduced in accordance with the test methods and procedures of this part unless the Administrator:

* * * * *

22. Section 75.24 is amended by revising paragraph (d) to read as follows:

§ 75.24 Out-of-control periods.

* * * * *

(d) When the bias test indicates that an SO_2 monitor, volumetric flow monitor, or NO_X continuous emission monitoring system is biased low (i.e., the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test or calculate and use the bias adjustment factor as specified in section 2.3.4 of appendix B to this part and in accordance with § 75.7.

* * * * *

23. Section 75.30 is amended by revising paragraphs (a)(2) and (d) to read as follows:

§ 75.30 General provisions.

(a) * * *

(2) A valid quality assured hour of flow data (in scfh) has not been measured and recorded for an affected unit from a certified flow monitor, or from a certified excepted flow monitoring system under appendix I to this part, or by an approved alternative monitoring system under subpart E of this part; or

* * * * *

(d) The owner or operator shall comply with the applicable provisions of this paragraph during hours in which a unit with an SO_2 continuous emission monitoring system combusts only natural gas or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas.

(1) Whenever a unit with an SO_2 continuous emission monitoring system combusts only pipeline natural gas and the owner or operator is using the procedures in section 7 of appendix F to this part to determine SO_2 mass emissions pursuant to § 75.11(e)(1), the owner or operator shall, for purposes of reporting heat input data under § 75.54(b)(5) or § 75.57(b)(5), as applicable, and for the calculation of SO_2 mass emissions using Equation F–23 in section 7 of appendix F to this part, substitute for missing data from a flow monitoring system, CO_2-diluent monitor or O_2-diluent monitor using the missing data substitution procedures in § 75.36.

(2) Whenever a unit with an SO_2 continuous emission monitoring system combusts gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≥20 gr/100 scf) and the owner or operator uses the gas sampling and analysis and fuel flow procedures in appendix D to this part to determine SO_2 mass emissions pursuant to § 75.11(e)(2), the owner or operator shall substitute for missing total sulfur content, gross calorific value, and fuel flowmeter data using the missing data procedures in appendix D to this part and shall also, for purposes of reporting heat input data under § 75.54(b)(5) or § 75.57(b)(5), substitute for missing data from a flow monitoring system, CO_2-diluent monitor, or O_2-diluent monitor using the missing data substitution procedures in § 75.36.

(3) The owner or operator of a unit with an SO_2 monitoring system shall not include hours, when the unit combusts only natural gas (or a gaseous fuel with total sulfur content no greater than the total sulfur content of natural gas), in the SO_2 data availability calculations in § 75.32 or in the calculations of substitute SO_2 data using the procedures of either § 75.31 or § 75.33, when SO_2 emissions are determined in accordance with § 75.11(e)(1) or (e)(2). For the purpose of the missing data and availability procedures for SO_2 pollutant concentration monitors in §§ 75.31 and 75.33 only, all hours during which the unit combusts only natural gas, or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas, shall be excluded from the definition of ''monitor operating hour,'' ''quality assured monitor operating hour,'' ''unit operating hour,'' and ''unit operating day,'' when SO_2 emissions are determined in accordance with § 75.11(e)(1) or (e)(2).

(4) During all hours in which a unit with an SO_2 continuous emission monitoring system combusts only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) and the owner or operator uses the SO_2 monitoring system to determine SO_2 mass emissions pursuant to § 75.11(e)(3), the owner or operator shall determine the percent monitor data availability for SO_2 in accordance with § 75.32 and shall use the standard SO_2 missing data procedures of § 75.33.

24. Section 75.32 is amended by revising the last sentence in paragraph (a)(3) to read as follows:

§ 75.32 Determination of monitor data availability for standard missing data procedures.

(a) * * *

(3) * * * The owner or operator of a unit with an SO_2 monitoring system shall, when SO_2 emissions are determined in accordance with § 75.11(e)(1) or (e)(2), exclude hours in which a unit combusts only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) from calculations of percent monitor data availability for SO_2 pollutant concentration monitors, as provided in § 75.30(d).

* * * * *

25. Section 75.33 is amended by adding a new paragraph (d) to read as follows:

§ 75.33 Standard missing data procedures.

* * * * *

(d) On and after January 1, 2000, failure to maintain a monitor data availability, as calculated pursuant to § 75.32, of at least 80.0 percent for SO_2, NO_X, flow rate, or CO_2 shall be considered a violation of the primary measurement requirement of § 75.10(a). This paragraph (d) shall not apply: if, for a particular unit or stack for which the monitor data availability drops below 80.0 percent, less than 3,000 unit operating hours have been accumulated in the previous 12 calendar quarters; or if a data availability percentage of less than 80.0 percent results from a sudden and reasonably unforeseeable event beyond the control of the owner or operator, such as catastrophic monitor failure or destruction of monitoring equipment by fire, flood, etc. If such

circumstances have caused (or are projected to cause) the monitor data availability to drop below 80.0 percent, the owner or operator shall notify the Administrator, in writing, within 7 days of the event(s). Notification, in writing, shall also be provided to the EPA Regional Office and to the appropriate State agency. The written notifications shall fully explain the circumstances that have caused (or may cause) the low monitor data availability and shall contain an action plan and a projected time schedule for correction of the problem. Failures that are caused in part by poor maintenance or careless operation shall not, for the purposes of this paragraph, be considered reasonably unforeseeable events beyond the control of the owner or operator.

26. Section 75.34 is amended by revising paragraph (a)(3) to read as follows:

§ 75.34 Units with add-on emission controls.

(a) * * *

(3) The designated representative may petition the Administrator under § 75.66 for approval of site-specific parametric monitoring procedure(s) for calculating substitute data for missing SO_2 pollutant concentration and NO_X emission rate data in accordance with the requirements of paragraphs (b) and (c) of this section and appendix C to this part. The owner or operator shall record the data required in appendix C to this part, pursuant to § 75.55(b) or § 75.58(b), as applicable.

* * * * *

27. Section 75.35 is amended by revising paragraphs (a) and (c) to read as follows:

§ 75.35 Missing data procedures for CO_2 data.

(a) On and after January 1, 2000, the owner or operator of a unit with a CO_2 continuous emission monitoring system (or an O_2-diluent monitor that is used to determine CO_2 concentration in accordance with appendix F to this part) shall substitute for missing CO_2 concentration data using the procedures of this section. Prior to January 1, 2000, the owner or operator may substitute for missing CO_2 or O_2 concentration data using the procedures of this section.

* * * * *

(c) Upon completion of the first 720 quality assured monitor operating hours following initial certification of the CO_2 continuous emission monitoring system, the owner or operator shall provide substitute data for CO_2 concentration or CO_2 mass emissions required under this subpart, including CO_2 data calculated from O_2 measurements using the procedures in appendix F to this part, in accordance with the procedures in § 75.33(b), except that the terms ''SO_2 concentration'' and ''SO_2 pollutant concentration monitor'' shall be replaced, respectively, with ''CO_2 concentration'' and ''CO_2 pollutant concentration monitor.''

28. Section 75.36 is amended by revising paragraphs (a), (b), and (c) to read as follows:

§ 75.36 Missing data procedures for heat input.

(a) When hourly heat input is determined using a flow monitoring system and a diluent gas (O_2 or CO_2) monitor, substitute data must be provided to calculate the heat input whenever quality assured data are unavailable from the flow monitor, the diluent gas monitor, or both. When flow rate data are unavailable, substitute flow rate data for the heat input calculation shall be provided according to § 75.31 or § 75.33, as applicable. On and after January 1, 2000, when diluent gas data are unavailable, the owner or operator shall provide substitute O_2 or CO_2 data for the heat input calculations in accordance with this section. Prior to January 1, 2000, the owner or operator may substitute for missing CO_2 or O_2 concentration data using the procedures in this section.

(b) During the first 720 quality assured monitor operating hours following initial certification (i.e., following the date and time of completion of successful certification tests of the CO_2 or O_2 monitor), the owner or operator shall provide substitute CO_2 or O_2 data, as applicable, for the calculation of heat input (under section 5.2 of appendix F to this part) according to § 75.31(b).

(c) Upon completion of the first 720 quality assured monitor operating hours following initial certification of the CO_2 (or O_2) monitor, the owner or operator shall provide substitute data for CO_2 or O_2 concentration to calculate heat input according to the procedures in § 75.33(b), except that the term ''SO_2 concentration'' shall be replaced with ''CO_2 concentration'' or ''O_2 concentration'' (as applicable) and the term ''SO_2 pollutant concentration monitor'' shall be replaced with ''CO_2-diluent monitor'' or ''O_2-diluent monitor'' (as applicable).

* * * * *

29. Section 75.37 is added to subpart D to read as follows:

§ 75.37 Missing data procedures for moisture.

The owner or operator shall substitute for missing moisture data (beginning no later than January 1, 2000 or the date and hour on which the unit or stack is required to begin reporting under § 75.64, whichever date is earlier) as follows:

(a) Where no prior quality assured percent moisture data exist, substitute 0.0 percent moisture for each unit operating hour;

(b) For the first 720 quality assured monitor operating hours, substitute for each hour of the missing data period the average of the percent moisture values obtained during the hour before and the hour after the missing data period;

(c) Once 720 quality assured monitor operating hours have been obtained, begin calculating the percent data availability of the moisture monitoring system, in accordance with § 75.32;

(d) When the percent data availability, as of the last hour in the missing data period, is ≥90.0 percent, substitute for each hour of the missing data period the average of the percent moisture values obtained during the hour before and the hour after the missing data period;

(e) If the percent data availability of the moisture monitor is < 90.0 percent as of the last hour in the missing data period, substitute 0.0 percent moisture for each hour of the missing data period.

Subpart E—[Amended]

30. Section 75.48 is amended by revising paragraphs (a)(3)(ii) and (a)(3)(iii) to read as follows:

§ 75.48 Petition for an alternative monitoring system.

(a) * * *

(3) * * *

(ii) Hourly test data for the alternative monitoring system at each required operating level and fuel type. The fuel type, operating level and gross unit load shall be recorded.

(iii) Hourly test data for the continuous emissions monitoring system at each required operating level and fuel type. The fuel type, operating level and gross unit load shall be recorded.

* * * * *

31. Section 75.50 is removed and reserved.

§ 75.50 [Removed and Reserved]

32. Section 75.51 is removed and reserved.

§ 75.51 [Removed and Reserved]

33. Section 75.52 is removed and reserved.

§ 75.52 [Removed and Reserved]

34. Section 75.53 is amended by revising paragraphs (a) and (b) and adding paragraphs (e) through (f) to read as follows:

§ 75.53 Monitoring plan.

(a) *General Provisions.*

(1) Compliance dates. Beginning on January 1, 2000, the owner or operator shall comply with the provisions in paragraphs (a), (b), (e) and (f) of this section only. Before January 1, 2000, the owner or operator shall comply with either paragraphs (a) through (d) or paragraphs (a), (b), (c), and (f) of this section, except that the owner or operator shall comply with provisions in paragraphs (e) and (f) of this section only before January 1, 2000, when those provisions support a regulatory option provided in another section of this part 75 and the regulatory option is exercised before January 1, 2000.

(2) The owner or operator of an affected unit shall prepare and maintain a monitoring plan. Except as provided in paragraphs (d) (or (f), as applicable) of this section, a monitoring plan shall contain sufficient information on the continuous emission or opacity monitoring systems, excepted methodology under § 75.19, or excepted monitoring systems under appendix D or E to this part and the use of data derived from these systems to demonstrate that all unit SO_2 emissions, NO_X emissions, CO_2 emissions, and opacity are monitored and reported.

(b) Whenever the owner or operator makes a replacement, modification, or change in the certified continuous emission monitoring system, continuous opacity monitoring system, excepted methodology under § 75.19, excepted monitoring system under appendix D, E, or I to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan.

* * * * *

(e) *Contents of the monitoring plan.* Each monitoring plan shall contain the information in paragraph (e)(1) of this section in electronic format and the information in paragraph (e)(2) of this section in hardcopy format.

(1) *Electronic.* (i) ORISPL numbers developed by the Department of Energy and used in the National Allowance Database, for all affected units involved in the monitoring plan, with the following information for each unit:

(A) Short name;

(B) Classification of unit as one of the following: Phase I (including substitution or compensating units), Phase II, new, or nonaffected;

(C) Type of boiler (or boilers for a group of units using a common stack);

(D) Type of fuel(s) fired by boiler, fuel type start and end date, primary/secondary fuel indicator, and, if more than one fuel, the fuel classification of the boiler;

(E) Type(s) of emission controls for SO_2, NO_X, and particulates installed or to be installed, including specifications of whether such controls are pre-combustion, post-combustion, or integral to the combustion process; control equipment code, installation date, and optimization date; control equipment retirement date (if applicable); and, an indicator for whether the controls are an original installation;

(F) Maximum hourly heat input capacity;

(G) Date of first commercial operation;

(H) Unit retirement date (if applicable);

(I) Maximum hourly gross load (in MW, rounded to the nearest MW, or steam load in 1000 lb/hr, rounded to the nearest 100 lb/hr);

(J) Identification of all units using a common stack;

(K) Activation date for the stack/pipe;

(L) Retirement date of the stack/pipe (if applicable); and

(M) Indicator of whether the stack is a bypass stack.

(ii) For each unit and parameter required to be monitored, identification of monitoring methodology information, consisting of monitoring methodology, type of fuel associated with the methodology, missing data approach for the methodology, methodology start date, and methodology end date (if applicable).

(iii) The following information:

(A) Program(s) for which the EDR is submitted;

(B) Unit classification;

(C) Reporting frequency;

(D) Program participation date;

(E) State regulation code (if applicable); and

(F) State or local regulatory agency code.

(iv) Identification and description of each monitoring component (including each monitor and its identifiable components, such as analyzer and/or probe) in the continuous emission monitoring systems (i.e., SO_2 pollutant concentration monitor, flow monitor, moisture monitor; NO_X pollutant concentration monitor and diluent gas monitor), the continuous opacity monitoring system, or excepted monitoring system (i.e., fuel flowmeter, data acquisition and handling system), including:

(A) Manufacturer, model number and serial number;

(B) Component/system identification code assigned by the utility to each identifiable monitoring component (such as the analyzer and/or probe). Each code shall use a three-digit format, unique to each monitoring component and unique to each monitoring system;

(C) Designation of the component type or method of operation, such as in situ pollutant concentration monitor or thermal flow monitor;

(D) Designation of the system as a primary, redundant backup, non-redundant backup, like kind non-redundant backup, data backup, or reference method backup system, as provided in § 75.10(e);

(E) First and last dates the system reported data; and

(F) Status of the monitoring component.

(v) Identification and description of all major hardware and software components of the automated data acquisition and handling system, including:

(A) For hardware components, the manufacturer and model number; and

(B) For software components, identification of the provider and model/version number.

(vi) Explicit formulas for each measured emission parameter, using component/system identification codes for the primary system used to measure the parameter to link continuous emission monitoring system or excepted monitoring system observations with reported concentrations, mass emissions, or emission rates, according to the conversions listed in appendix D, E, or F to this part. Formulas for backup monitoring systems are required only if different formulas for the same parameter are used for the primary and backup monitoring systems (e.g., if the primary system measures pollutant concentration on a different moisture basis from the backup system). The formulas must contain all constants and factors required to derive mass emissions or emission rates from component/system code observations and an indication of whether the formula is being added, corrected, deleted, or is unchanged. Each emissions formula is identified with a unique three digit code. The owner or operator of a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c) is not required to report such formulas.

(vii) Inside cross-sectional area (ft^2) at flue exit (for all units) and at flow monitoring location (for units with flow monitors, only).

(viii) Stack height (ft) above ground level and stack base elevation above sea level.

(ix) Flue identification number, as reported to the Energy Information Administration (EIA).

(x) For each parameter monitored: scale, maximum potential concentration (and method of calculation), maximum expected concentration (if applicable) (and method of calculation), maximum potential flow rate (and method of calculation), maximum potential NO_X emission rate, span value, full-scale range, daily calibration units of measure, span effective date/hour, span inactivation date/hour, indication of whether dual spans are required, default high range value, flow rate span, and flow rate span value and full scale value (in scfh) for each unit or stack using SO_2, NO_X, CO_2, O_2, or flow component monitors.

(xi) If the monitoring system or excepted methodology provides for the use of a constant, assumed, or default value for a parameter under specific circumstances, then include the following information for each such value for each parameter:

(A) Identification of the parameter;

(B) Default, maximum, minimum, or constant value, and units of measure for the value;

(C) Purpose of the value;

(D) Indicator of use during controlled/uncontrolled hours;

(E) Type of fuel;

(F) Source of the value;

(G) Value effective date and hour;

(H) Date and hour value is no longer effective (if applicable); and

(I) For units using the excepted methodology under § 75.19, the applicable SO_2 emission factor.

(2) *Hardcopy.* (i) Information, including (as applicable) identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity check; calculations for determining maximum potential concentration, maximum expected concentration (if applicable), maximum potential flow rate, maximum potential NO_X emission rate, and span; and apportionment strategies under §§ 75.13 through 75.17.

(ii) Description of site locations for each monitoring component in the continuous emission or opacity monitoring systems, including schematic diagrams and engineering drawings specified in paragraphs (e)(2)(iv) and (e)(2)(v) of this section and any other documentation that demonstrates each monitor location meets the appropriate siting criteria.

(iii) A data flow diagram denoting the complete information handling path from output signals of continuous emission monitoring system components to final reports.

(iv) For units monitored by a continuous emission or opacity monitoring system, a schematic diagram identifying entire gas handling system from boiler to stack for all affected units, using identification numbers for units, monitor components, and stacks corresponding to the identification numbers provided in paragraphs (e)(1)(i), (e)(1)(ii), (e)(1)(vi), and (e)(1)(vii) of this section. The schematic diagram must depict stack height and the height of any monitor locations. Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common stack.

(v) For units monitored by a continuous emission or opacity monitoring system, stack and duct engineering diagrams showing the dimensions and location of fans, turning vanes, air preheaters, monitor components, probes, reference method sampling ports, and other equipment that affects the monitoring system location, performance, or quality control checks.

(f) *Contents of monitoring plan for specific situations.* The following additional information shall be included in the monitoring plan for the specific situations described:

(1) For each gas-fired unit or oil-fired unit for which the owner or operator uses the optional protocol in appendix D to this part for estimating heat input and/or SO_2 mass emissions or in appendix I to this part for estimating stack flow rate, or for each gas-fired or oil-fired peaking unit for which the owner/operator uses the optional protocol in appendix E to this part for estimating NO_X emission rate (using a fuel flowmeter), the designated representative shall include the following additional information in the monitoring plan:

(i) *Electronic.* (A) Parameter monitored;

(B) Type of fuel measured, maximum fuel flow rate, units of measure, and basis of maximum fuel flow rate (i.e., upper range value or unit maximum) for each fuel flowmeter;

(C) Test method used to check the accuracy of each fuel flowmeter;

(D) Submission status of the data; and

(E) Monitoring system identification code.

(ii) *Hardcopy.* (A) A schematic diagram identifying the relationship between the unit, all fuel supply lines, the fuel flowmeter(s), and the stack(s). The schematic diagram must depict the installation location of each fuel flowmeter and the fuel sampling location(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe.

(B) For units using the optional protocol for gaseous fuel in appendix D to this part, historical fuel sampling information on the sulfur content of the gaseous fuel according to section 2.3.3 of appendix D to this part.

(2) For each gas-fired peaking unit and oil-fired peaking unit for which the owner or operator uses the optional procedures in appendix E to this part for estimating NO_X emission rate, the designated representative shall include in the monitoring plan:

(i) *Electronic.* Unit operating and capacity factor information demonstrating that the unit qualifies as a peaking unit or gas-fired unit, as defined in § 72.2 of this chapter.

(ii) *Hardcopy.* (A) A protocol containing methods used to perform the baseline or periodic NO_X emission test; and

(B) Unit operating parameters related to NO_X formation by the unit.

(3) For each gas-fired unit and diesel-fired unit or unit with a wet flue gas pollution control system for which the designated representative claims an opacity monitoring exemption under § 75.14, the designated representative shall include in the hardcopy monitoring plan the information specified under § 75.14(b), (c), or (d), demonstrating that the unit qualifies for the exemption.

(4) For each monitoring system recertification, maintenance, or other event, the designated representative shall include the following additional information in electronic format in the monitoring plan:

(i) Component/system identification code;

(ii) Event code or code for required test;

(iii) Event begin date and hour;

(iv) Conditional data period begin date and hour (if applicable);

(v) Date and hour that last test is successfully completed; and

(vi) Indicator of whether conditionally valid data were reported at the end of the quarter.

35. Section 75.54 is amended by adding new paragraphs (g) and (h) to read as follows:

§ 75.54 General recordkeeping provisions.

* * * * *

(g) *Missing data records.* The owner or operator shall record the causes of any missing data periods and the actions

taken by the owner or operator to cure such causes.

(h) *Compliance dates.* On January 1, 2000, the provisions of this section are no longer applicable. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.57. Beginning on January 1, 2000, the owner or operator shall comply with § 75.57 only.

36. Section 75.55 is amended by adding a new paragraph (g) to read as follows:

§ 75.55 General recordkeeping provisions for specific situations.

* * * * *

(g) *Compliance dates.* On January 1, 2000, the provisions of this section are no longer applicable. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.58. Beginning on January 1, 2000, the owner or operator shall comply with § 75.58 only.

37. Section 75.56 is amended by adding new paragraphs (a)(5)(vii) and (e) to read as follows:

§ 75.56 Certification, quality assurance, and quality control record provisions.

(a) * * *

(5) * * *

(vii) For flow monitors, the flow polynomial equation used to linearize the flow monitor and the numerical values of the polynomial coefficients of that equation.

* * * * *

(e) *Compliance dates.* On January 1, 2000, the provisions of this section are no longer applicable. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.59. Beginning on January 1, 2000, the owner or operator shall comply with § 75.59 only.

38. Section 75.57 is added to Subpart F to read as follows:

§ 75.57 General recordkeeping provisions.

(a) *Recordkeeping requirements for affected sources.* The owner or operator of any affected source subject to the requirements of this part shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Unless otherwise provided, throughout this subpart the phrase ''for each affected unit'' also applies to each group of affected or nonaffected units utilizing a common stack and common monitoring systems, pursuant to §§ 75.13 through 75.18, or utilizing a common pipe header and common fuel flowmeter, pursuant to section 2.1.2 of appendix D to this part. The file shall contain the following information:

(1) The data and information required in paragraphs (b) through (f) of this section, beginning with the earlier of the date of provisional certification or the deadline in § 75.4(a), (b), or (c);

(2) The supporting data and information used to calculate values required in paragraphs (b) through (f) of this section, excluding the subhourly data points used to compute hourly averages under § 75.10(d), beginning with the earlier of the date of provisional certification or the deadline in § 75.4(a), (b), or (c);

(3) The data and information required in § 75.55 or § 75.58 for specific situations, as applicable, beginning with the earlier of the date of provisional certification or the deadline in § 75.4(a), (b), or (c);

(4) The certification test data and information required in § 75.56 or § 75.59 for tests required under § 75.20, beginning with the date of the first certification test performed; the quality assurance and quality control data and information required in § 75.56 or § 75.59 for tests; and the quality assurance/quality control plan required under § 75.21 and appendix B to this part, beginning with the date of provisional certification;

(5) The current monitoring plan as specified in § 75.53, beginning with the initial submission required by § 75.62; and

(6) The quality control plan as described in section 1 of appendix B to this part, beginning with the date of provisional certification.

(b) *Operating parameter record provisions.* The owner or operator shall record for each hour the following information on unit operating time, heat input rate, and load, separately for each affected unit and also for each group of units utilizing a common stack and a common monitoring system or utilizing a common pipe header and common fuel flowmeter.

(1) Date and hour;

(2) Unit operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator));

(3) Hourly gross unit load (rounded to nearest MWge) (or steam load in 1000 lb/hr at stated temperature and pressure, rounded to the nearest 1000 lb/hr, if elected in the monitoring plan);

(4) Operating load range corresponding to hourly gross load of 1 to 10, except for units using a common stack or common pipe header, which may use up to 20 load ranges for stack or fuel flow, as specified in the monitoring plan;

(5) Hourly heat input rate (mmBtu/hr, rounded to the nearest tenth);

(6) Identification code for formula used for heat input, as provided in § 75.53; and

(7) For CEMS units only:

(i) F-factor for heat input calculation; and

(ii) Indication of whether the diluent cap was used for heat input calculations for the hour.

(c) *SO_2 emission record provisions.* The owner or operator shall record for each hour the information required by this paragraph for each affected unit or group of units using a common stack and common monitoring systems, except as provided under § 75.11(e) or for a gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part or for a low mass emissions unit for which the owner or operator is using the optional low mass emissions methodology in § 75.19(c) for estimating SO_2 mass emissions:

(1) For SO_2 concentration during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component-system identification code, as provided in § 75.53;

(ii) Date and hour;

(iii) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth);

(iv) Hourly average SO_2 concentration (ppm, rounded to the nearest tenth), adjusted for bias if bias adjustment factor is required, as provided in § 75.24(d);

(v) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32; and

(vi) Method of determination for hourly average SO_2 concentration using Codes 1–55 in Table 4a of this section.

(2) For flow rate during unit operation, as measured and reported from each certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component system identification code, as provided in § 75.53 (including the separate identification code for the moisture monitoring system, if applicable);

(ii) Date and hour;

(iii) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand);

(iv) Hourly average volumetric flow rate (in scfh, rounded to the nearest thousand), adjusted for bias if bias

adjustment factor required, as provided in § 75.24(d);

(v) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth), where SO_2 concentration is measured on a dry basis. If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, record both the wet- and dry-basis oxygen hourly averages (in percent O_2, rounded to the nearest tenth);

(vi) Percent monitor data availability (recorded to the nearest tenth of a percent), for the flow monitor, and, if applicable, separately for the moisture monitoring system, calculated pursuant to § 75.32; and

(vii) Method of determination for hourly average flow rate using Codes 1–55 in Table 4a of this section.

(3) For SO_2 mass emission rate during unit operation, as measured and reported from the certified primary monitoring system(s), certified redundant or non-redundant back-up monitoring system(s), or other approved method(s) of emissions determination:

(i) Date and hour;

(ii) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth);

(iii) Hourly SO_2 mass emission rate (lb/hr, rounded to the nearest tenth), adjusted for bias if bias adjustment factor required, as provided in § 75.24(d); and

(iv) Identification code for emissions formula used to derive hourly SO_2 mass emission rate from SO_2 concentration and flow data in paragraphs (c)(1) and (c)(2) of this section, as provided in § 75.53.

TABLE 4A.—CODES FOR METHOD OF EMISSIONS AND FLOW DETERMINATION

Code	Hourly emissions/flow measurement or estimation method
1	Certified primary emission/flow monitoring system.
2	Certified backup emission/flow monitoring system.
3	Approved alternative monitoring system.
4	Reference method: SO_2: Method 6C. Flow: Method 2. NO_X: Method 7E. CO_2 or O2: Method 3A.
5	For units with add-on SO_2 and/or NO_X emission controls: SO_2 concentration or NO_X emission rate estimate from Agency preapproved parametric monitoring method.
6	Average of the hourly SO_2 concentrations, CO_2 concentrations, flow rate, or NO_X emission rate for the hour before and the hour following a missing data period.
7	Hourly average SO_2 concentration, CO_2 concentration, flow rate, or NO_X emission rate using initial missing data procedures.
8	90th percentile hourly SO_2 concentration, flow rate, or emission rate.
9	95th percentile hourly SO_2 concentration, flow rate, or NO_X emission rate.
10	Maximum hourly SO_2 concentration, flow rate, or NO_X emission rate.
11	Hourly average flow rate or NO_X emission rate in corresponding load range.
12	Maximum potential concentration of SO_2, maximum potential concentration of CO_2, maximum potential flow rate, or maximum potential NO_X emission rate, as determined using section 2.1 of appendix A to this part.
13	Fuel analysis data from appendix G to this part for CO_2 mass emissions. (This code is optional through 12/31/99, and shall not be used after 1/1/00.)
14	Diluent cap value (if the cap is replacing a CO_2 measurement, it shall be 5.0 percent for boilers and 1.0 percent for turbines; if it is replacing an O_2 measurement, it shall be 14.0 percent for boilers and 19.0 percent for turbines.
15	Fuel analysis data from appendix G to this part for CO_2 mass emissions. (This code is optional through 12/31/99, and shall not be used after 1/1/00.)
16	SO_2 concentration value of 2 ppm during hours when only natural gas (or fuel with equivalent sulfur content) is combusted.
19	200.0 percent of the MPC; default high range value.
20	200.0 percent of the full-scale range setting (full-scale exceedance of high range).
40	Stack volumetric flow calculated using the procedures of appendix I.
54	Other quality assured methodologies approved through petition. These hours are included in missing data lookback and are included as unavailable hours for percent monitor availability calculations.
55	Other substitute data approved through petition. These hours are not included in missing data lookback and are included as unavailable hours for percent monitor availability calculations.

(d) *NO_X emission record provisions.* The owner or operator shall record the information required by this paragraph for each affected unit for each hour, or partial hour during which the unit operates, except for a gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in appendix E to this part or a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c) for estimating NO_X emission rate. For each NO_X emission rate as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(1) Component system identification code, as provided in § 75.53 (including identification code for the moisture monitoring system, if applicable);

(2) Date and hour;

(3) Hourly average concentration (ppm, rounded to the nearest tenth);

(4) Hourly average diluent gas concentration (percent O_2 or percent CO_2, rounded to the nearest tenth) and, if applicable, the hourly average moisture content of the stack gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O_2, rounded to the nearest tenth);

(5) Hourly average NO_X emission rate (lb/mmBtu, rounded either to the nearest hundredth or thousandth prior to January 1, 2000 and rounded to the nearest thousandth on and after January 1, 2000);

(6) Hourly average NO_X emission rate (lb/mmBtu, rounded either to the nearest hundredth or thousandth prior to January 1, 2000 and rounded to the nearest thousandth on and after January 1, 2000), adjusted for bias if bias adjustment factor is required, as provided in § 75.24(d). The requirement to report hourly NO_X emission rates to the nearest thousandth shall not affect NO_X compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu;

(7) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_X

monitoring system, and, if applicable, separately for the moisture monitoring system, calculated pursuant to § 75.32;

(8) Method of determination for hourly average NO_X emission rate using Codes 1–55 in Table 4a of this section;

(9) Identification code for emissions formulas used to derive hourly average NO_X emission rate and total NO_X mass, as provided in § 75.53, and F-factor used to convert NO_X concentrations into emission rates;

(e) *CO_2 emission record provisions.* Except for a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c) for estimating CO_2 mass emissions, the owner or operator shall record or calculate CO_2 emissions for each affected unit using one of the following methods specified in this section:

(1) If the owner or operator chooses to use a CO_2 continuous emission monitoring system (including an O_2 monitor and flow monitor, as specified in appendix F to this part), then the owner or operator shall record for each hour or partial hour during which the unit operates the following information for CO_2 mass emissions, as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(i) Component/system identification code, as provided in § 75.53;

(ii) Date and hour;

(iii) Hourly average CO_2 concentration (in percent, rounded to the nearest tenth);

(iv) Hourly average volumetric flow rate (scfh, rounded to the nearest thousand scfh);

(v) Hourly average moisture content of flue gas (percent, rounded to the nearest tenth), where CO_2 concentration is measured on a dry basis. If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O_2, rounded to the nearest tenth);

(vi) Hourly average CO_2 mass emission rate (tons/hr, rounded to the nearest tenth);

(vii) Percent monitor data availability for both the CO_2 monitoring system and, if applicable, the moisture monitoring system (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32;

(viii) Method of determination for hourly average CO_2 mass emission rate using Codes 1–55 in Table 4a of this section;

(ix) Identification code for emissions formula used to derive hourly average CO_2 mass emission rate, as provided in § 75.53; and

(x) Indication of whether the diluent cap was used for CO_2 calculation for the hour.

(2) As an alternative to paragraph (e)(1) of this section, the owner or operator may use the procedures in § 75.13 and in appendix G to this part, and shall record daily the following information for CO_2 mass emissions:

(i) Date;

(ii) Daily combustion-formed CO_2 mass emissions (tons/day, rounded to the nearest tenth);

(iii) For coal-fired units, flag indicating whether optional procedure to adjust combustion-formed CO_2 mass emissions for carbon retained in flyash has been used and, if so, the adjustment;

(iv) For a unit with a wet flue gas desulfurization system or other controls generating CO_2, daily sorbent-related CO_2 mass emissions (tons/day, rounded to the nearest tenth); and

(v) For a unit with a wet flue gas desulfurization system or other controls generating CO_2, total daily CO_2 mass emissions (tons/day, rounded to the nearest tenth) as sum of combustion-formed emissions and sorbent-related emissions.

(f) *Opacity records.* The owner or operator shall record opacity data as specified by the State or local air pollution control agency. If the State or local air pollution control agency does not specify recordkeeping requirements for opacity, then record the information required by paragraphs (f) (1) through (5) of this section for each affected unit, except as provided in § 75.14 (b), (c), and (d). The owner or operator shall also keep records of all incidents of opacity monitor downtime during unit operation, including reason(s) for the monitor outage(s) and any corrective action(s) taken for opacity, as measured and reported by the continuous opacity monitoring system:

(1) Component/system identification code;

(2) Date, hour, and minute;

(3) Average opacity of emissions for each six minute averaging period (in percent opacity);

(4) If the average opacity of emissions exceeds the applicable standard, then a code indicating such an exceedance has occurred; and

(5) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated according to the requirements of the procedure recommended for State Implementation Plans in appendix M to part 51 of this chapter.

(g) *O_2-diluent record provisions.* The owner or operator of a unit using a flow monitor and an O_2-diluent monitor to determine heat input, in accordance with Equation F–17 or F–18 of appendix F to this part, shall keep the following records for the O_2-diluent monitor:

(1) Component-system identification code, as provided in § 75.53;

(2) Date and hour;

(3) Hourly average O2 concentration (in percent, rounded to the nearest tenth);

(4) Percent monitor data availability (recorded to the nearest tenth of a percent), calculated pursuant to § 75.32;

(5) Method of determination code for O_2 concentration data using Codes 1–55, substituting the words ''O_2 concentrations'' and ''O_2 concentration'' for the words ''CO_2 concentrations'' and CO_2 concentration'' in the descriptions of Codes 6 and 7 in Table 4a of this section, respectively.

(h) *Missing data records.* The owner or operator shall record the causes of any missing data periods and the actions taken by the owner or operator to cure such causes.

(i) Compliance dates. Beginning on January 1, 2000, the owner or operator shall comply with the provisions in paragraphs (a), (b), (e) and (f) of this section only. Before January 1, 2000, the owner or operator shall comply with either paragraphs (a) through (d) or paragraphs (a), (b), (c), and (f) of this section, except that the owner or operator shall comply with provisions in paragraphs (e) and (f) of this section only before January 1, 2000, when those provisions support a regulatory option provided in another section of this part 75 and the regulatory option is exercised before January 1, 2000.

39. Section 75.58 is added to read as follows:

§ 75.58 General recordkeeping provisions for specific situations.

(a) *Specific SO_2 emission record provisions for units with qualifying Phase I technology.* In addition to the SO_2 emissions information required in § 75.54(c), from January 1, 1997 through December 31, 1999, the owner or operator shall record the applicable information in this paragraph for each affected unit on which SO_2 emission controls have been installed and operated for the purpose of meeting qualifying Phase I technology requirements pursuant to § 72.42 of this chapter and § 75.15.

(1) For units with post-combustion emission controls:

(i) Component/system identification codes for each inlet and outlet SO_2-diluent continuous emission monitoring system;

(ii) Date and hour;

(iii) Hourly average inlet SO_2 emission rate during unit operation (lb/mmBtu, rounded to nearest hundredth);

(iv) Hourly average outlet SO_2 emission rate during unit operation (lb/mmBtu, rounded to nearest hundredth);

(v) Percent data availability for both inlet and outlet SO_2-diluent continuous emission monitoring systems (recorded to the nearest tenth of a percent), calculated pursuant to Equation 8 of § 75.32 (for the first 8,760 unit operating hours following initial certification) and Equation 9 of § 75.32, thereafter; and

(vi) Identification code for emissions formula used to derive hourly average inlet and outlet SO_2 mass emissions rates for each affected unit or group of units using a common stack.

(2) For units with combustion and/or pre-combustion emission controls:

(i) Component/system identification codes for each outlet SO_2-diluent continuous emission monitoring system;

(ii) Date and hour;

(iii) Hourly average outlet SO_2 emission rate during unit operation (lb/mmBtu, rounded to nearest hundredth);

(iv) For units with combustion controls, average daily inlet SO_2 emission rate (lb/mmBtu, rounded to nearest hundredth), determined by coal sampling and analysis procedures in § 75.15; and

(v) For units with pre-combustion controls (i.e., fuel pretreatment), fuel analysis demonstrating the weight, sulfur content, and gross calorific value of the product and raw fuel lots.

(b) *Specific parametric data record provisions for calculating substitute emissions data for units with add-on emission controls.* In accordance with § 75.34, the owner or operator of an affected unit with add-on emission controls shall either record the applicable information in paragraph (b)(3) of this section for each hour of missing SO_2 concentration data or NO_X emission rate (in addition to other information), or shall record the information in paragraph (b)(1) of this section for SO_2 or paragraph (b)(2) of this section for NO_X through an automated data acquisition and handling system, as appropriate to the type of add-on emission controls:

(1) For units with add-on SO_2 emission controls petitioning to use or using the optional parametric monitoring procedures in appendix C to this part, for each hour of missing SO_2 concentration or volumetric flow data:

(i) The information required in § 75.54(b) or § 75.57(b) for SO_2 concentration and volumetric flow, if either one of these monitors is still operating;

(ii) Date and hour;

(iii) Number of operating scrubber modules;

(iv) Total feedrate of slurry to each operating scrubber module (gal/min);

(v) Pressure differential across each operating scrubber module (inches of water column);

(vi) For a unit with a wet flue gas desulfurization system, an in-line measure of absorber pH for each operating scrubber module;

(vii) For a unit with a dry flue gas desulfurization system, the inlet and outlet temperatures across each operating scrubber module;

(viii) For a unit with a wet flue gas desulfurization system, the percent solids in slurry for each scrubber module.

(ix) For a unit with a dry flue gas desulfurization system, the slurry feed rate (gal/min) to the atomizer nozzle;

(x) For a unit with SO_2 add-on emission controls other than wet or dry limestone, corresponding parameters approved by the Administrator;

(xi) Method of determination of SO_2 concentration and volumetric flow using Codes 1–55 in Table 4 of § 75.54 or Table 4a of § 75.57; and

(xii) Inlet and outlet SO_2 concentration values, recorded by an SO_2 continuous emission monitoring system, and the removal efficiency of the add-on emission controls.

(2) For units with add-on emission controls petitioning to use or using the optional parametric monitoring procedures in appendix C to this part, for each hour of missing NO_X emission rate data:

(i) Date and hour;

(ii) Inlet air flow rate (scfh, rounded to the nearest thousand);

(iii) Excess O_2 concentration of flue gas at stack outlet (percent, rounded to nearest tenth of a percent);

(iv) Carbon monoxide concentration of flue gas at stack outlet (ppm, rounded to the nearest tenth);

(v) Temperature of flue gas at furnace exit or economizer outlet duct (°F);

(vi) Other parameters specific to NO_X emission controls (e.g., average hourly reagent feedrate);

(vii) Method of determination of NO_X emission rate using Codes 1–55 in Table 4 of § 75.54 or Table 4a of § 75.57; and

(viii) Inlet and outlet NO_X emission rate values recorded by a NO_X continuous emission monitoring system and the removal efficiency of the add-on emission controls.

(3) For units with add-on SO_2 or NO_X emission controls following the provisions of § 75.34(a)(1) or (a)(2), the owner or operator shall, for each hour of missing SO_2 or NO_X emission data, record:

(i) Parametric data which demonstrate the proper operation of the add-on emission controls, as described in the quality assurance/quality control program for the unit. The parametric data shall be maintained on site and shall be submitted, upon request, to the Administrator, EPA Regional office, State, or local agency;

(ii) A flag indicating either that the add-on emission controls are operating properly, as evidenced by all parameters being within the ranges specified in the quality assurance/quality control program, or that the add-on emission controls are not operating properly;

(iii) For units petitioning under § 75.66 for substituting a representative SO_2 concentration during missing data periods, any available inlet and outlet SO_2 concentration values recorded by an SO_2 continuous emission monitoring system; and

(iv) For units petitioning under § 75.66 for substituting a representative NO_X emission rate during missing data periods, any available inlet and outlet NO_X emission rate values recorded by a continuous emission monitoring system.

(c) *Specific SO_2 emission record provisions for gas-fired or oil-fired units using optional protocol in appendix D to this part.* In lieu of recording the information in § 75.54(c) or § 75.57(c), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part for estimating SO_2 mass emissions.

(1) For each hour when the unit is combusting oil:

(i) Date and hour;

(ii) Hourly average flow rate of oil, while the unit combusts oil, with the units in which oil flow is recorded (gal/hr, lb/hr, m^3/hr, or bbl/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(iii) Sulfur content of oil sample used to determine SO_2 mass emission rate (rounded to nearest hundredth for diesel fuel or to the nearest tenth of a percent for other fuel oil) (flag value if derived from missing data procedures);

(iv) Method of oil sampling (flow proportional, continuous drip, as delivered, manual from storage tank, or daily manual);

(v) Mass rate of oil combusted each hour (lb/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(vi) SO_2 mass emission rate from oil (lb/hr, rounded to the nearest tenth);

(vii) For units using volumetric oil flowmeters, density of oil with the units in which oil density is recorded (flag

value if derived from missing data procedures);

(viii) Gross calorific value (heat content) of oil used to determine heat input (Btu/mass unit) (flag value if derived from missing data procedures);

(ix) Hourly heat input rate from oil, according to procedures in appendix F to this part (mmBtu/hr, to the nearest tenth);

(x) Fuel usage time for combustion of oil during the hour (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)) (flag to indicate multiple/single fuel types combusted); and

(xi) Monitoring system identification code.

(2) For gas-fired units or oil-fired units using the optional protocol in appendix D to this part for daily manual oil sampling, when the unit is combusting oil, the highest sulfur content recorded from the most recent 30 daily oil samples (rounded to nearest tenth of a percent).

(3) For gas-fired units or oil-fired units, using the optional protocol in appendix D to this part for using an assumed sulfur content or density, or for as-delivered fuel sampled from each delivery:

(i) Record the measured sulfur content, GCV and, if applicable, density from each fuel sample; and

(ii) Record and report the assumed sulfur content, GCV and, if applicable, density used to calculate SO_2 mass emission rate or heat input rate.

(4) For each hour when the unit is combusting gaseous fuel:

(i) Date and hour;

(ii) Hourly heat input rate from gaseous fuel, according to procedures in appendix F to this part (mmBtu/hr, rounded to the nearest tenth);

(iii) Sulfur content or SO_2 emission rate, in one of the following formats, in accordance with the appropriate procedure from appendix D to this part:

(A) Sulfur content of gas sample (rounded to the nearest 0.1 grains/100 scf) (flag value if derived from missing data procedures); or

(B) SO_2 emission rate from NADB or default SO_2 emission rate of 0.0006 lb/mmBtu for pipeline natural gas;

(iv) Hourly flow rate of gaseous fuel, while the unit combusts gas (100 scfh) (flag value if derived from missing data procedures);

(v) Gross calorific value (heat content) of gaseous fuel used to determine heat input rate (Btu/100 scf) (flag value if derived from missing data procedures);

(vi) Heat input rate from gaseous fuel, while the unit combusts gas (mmBtu/hr, rounded to the nearest tenth);

(vii) SO_2 mass emission rate due to the combustion of gaseous fuels (lb/hr);

(viii) Fuel usage time for combustion of gaseous fuel during the hour (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)) (flag to indicate multiple/single fuel types combusted); and

(ix) Monitoring system identification code.

(5) For each oil sample or sample of diesel fuel:

(i) Date of sampling;

(ii) Sulfur content (percent, rounded to the nearest hundredth for diesel fuel and to the nearest tenth for other fuel oil) (flag value if derived from missing data procedures);

(iii) Gross calorific value or heat content (Btu/lb) (flag value if derived from missing data procedures); and

(iv) Density or specific gravity, if required to convert volume to mass (flag value if derived from missing data procedures).

(6) For each sample of gaseous fuel for sulfur content:

(i) Date of sampling;

(ii) Sulfur content (grains/100 scf, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(7) For each sample of gaseous fuel for gross calorific value:

(i) Date of sampling; and

(ii) Gross calorific value or heat content (Btu/100 scf) (flag value if derived from missing data procedures).

(8) For each oil sample or sample of gaseous fuel:

(i) Type of oil or gas; and

(ii) Type of sulfur sampling and value used in calculations.

(d) *Specific NO_X emission record provisions for gas-fired peaking units or oil-fired peaking units using optional protocol in appendix E to this part.* In lieu of recording the information in paragraph § 75.54(d) or § 75.57(d), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in appendix E to this part for estimating NO_X emission rate. The owner or operator shall meet the requirements of this section, except that the requirements under paragraphs (d)(1)(vii), (d)(2)(vii), and (d)(3)(vi) of this section shall become applicable on the date on which the owner or operator is required to monitor, record, and report NO_X mass emissions under an applicable State or federal NO_X mass emission reduction program, if the provisions of subpart H of this part are adopted as requirements under such a program.

(1) For each hour when the unit is combusting oil:

(i) Date and hour;

(ii) Hourly average fuel flow rate of oil while the unit combusts oil with the units in which oil flow is recorded (gal/hour, lb/hr, or bbl/hour) (flag value if derived from missing data procedures);

(iii) Gross calorific value (heat content) of oil used to determine heat input (Btu/lb) (flag value if derived from missing data procedures);

(iv) Hourly average NO_X emission rate from combustion of oil (lb/mmBtu);

(v) Heat input rate of oil (mmBtu/hr, rounded to the nearest tenth;

(vi) Fuel usage time for combustion of oil during the hour (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)); and

(vii) NO_X mass emissions, calculated in accordance with section 8.1 of appendix F to this part.

(2) For each hour when the unit is combusting gaseous fuel:

(i) Date and hour;

(ii) Hourly average fuel flow rate of gaseous fuel, while the unit combusts gas (100 scfh) (flag value if derived from missing data procedures);

(iii) Gross calorific value (heat content) of gaseous fuel used to determine heat input (Btu/100 scf) (flag value if derived from missing data procedures);

(iv) Hourly average NO_X emission rate from combustion of gaseous fuel (lb/mmBtu, rounded to nearest hundredth);

(v) Heat input rate from gaseous fuel, while the unit combusts gas (mmBtu/hr, rounded to the nearest tenth);

(vi) Fuel usage time for combustion of gaseous fuel during the hour (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)); and

(vii) NO_X mass emissions, calculated in accordance with section 8.1 of appendix F to this part.

(3) For each hour when the unit combusts any fuel:

(i) Date and hour;

(ii) Hourly average heat input rate from all fuels (mmBtu/hr, rounded to the nearest tenth);

(iii) Hourly average NO_X emission rate for the unit for all fuels;

(iv) For stationary gas turbines and diesel or dual-fuel reciprocating engines, hourly averages of operating parameters under section 2.3 of appendix E to this part (flag if value is

outside of manufacturer's recommended range);

(v) For boilers, hourly average boiler O_2 reading (percent, rounded to the nearest tenth) (flag if value exceeds by more than 2 percentage points the O_2 level recorded at the same heat input during the previous NO_X emission rate test);

(vi) NO_X mass emissions, calculated in accordance with section 8.1 of appendix F to this part;

(vii) Segment ID of the correlation curve; and

(viii) Monitoring system identification code.

(4) For each fuel sample:

(i) Date of sampling;

(ii) Gross calorific value (heat content) (Btu/lb for oil, Btu/100 scf for gaseous fuel); and

(iii) Density or specific gravity, if required to convert volume to mass.

(e) *Specific SO_2 emission record provisions during the combustion of gaseous fuel.* (1) If SO_2 emissions are determined in accordance with the provisions in § 75.11(e)(2) during hours in which only natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) is combusted in a unit with an SO_2 continuous emission monitoring system, the owner or operator shall record the information in paragraph (c)(3) of this section in lieu of the information in §§ 75.54(c)(1) and (c)(3) or §§ 75.57(c)(1) and (c)(3), for those hours.

(2) The provisions of this paragraph apply to a unit which, in accordance with the provisions of § 75.11(e)(3), uses an SO_2 continuous emission monitoring system to determine SO_2 emissions during hours in which only natural gas or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas is combusted in the unit. If the unit sometimes burns only natural gas (or gaseous fuel with total sulfur content no greater than the total sulfur content of natural gas) as a primary and/or backup fuel and at other times combusts higher-sulfur fuels, such as coal or oil, as primary and/or backup fuel(s), then the owner or operator shall keep records on-site, suitable for inspection, of the type(s) of fuel(s) burned during each period of missing SO_2 data and the number of hours that each types of fuel was combusted in the unit during each missing data period. This recordkeeping requirement does not apply to an affected unit that burns natural gas (or gaseous fuel with a total sulfur content no greater than the total sulfur content of natural gas) exclusively, nor does it apply to a unit that burns such gaseous fuel(s) only during unit startup.

(f) *Specific SO_2, NO_X, and CO_2 record provisions for gas-fired or oil-fired units using the optional low mass emissions excepted methodology in § 75.19.* In lieu of recording the information in §§ 75.54(b) through (e) or § 75.57(b) through (e), the owner or operator shall record, for each hour when the unit is operating for any portion of the hour, the following information for each affected low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in § 75.19(c):

(1) Date and hour;

(2) Fuel type (pipeline natural gas, natural gas, residual oil, or diesel fuel) (note: if more than one type of fuel is combusted in the hour, indicate the fuel type which results in the highest emission factors for SO_2, CO_2, and NO_X);

(3) Average hourly NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth);

(4) Hourly NO_X mass emissions (lbs, rounded to the nearest tenth);

(5) Hourly SO_2 mass emissions (lbs, rounded to the nearest tenth); and

(6) Hourly CO_2 mass emissions (tons, rounded to the nearest tenth).

(g) *Specific provisions for gas-fired units or oil-fired units using optional protocol in appendix I to this part.* In addition to recording the information in § 75.54(c) or § 75.57(c), as applicable, the owner or operator shall record the applicable information in this paragraph for each affected unit for which the owner or operator is using the optional protocol in appendix I to this part. This includes:

(1) For each hour when the unit is combusting oil:

(i) Date and hour;

(ii) Hourly average flow rate of oil with the units in which oil flow is recorded (gal/hr, lb/hr, m^3/hr, or bbl/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(iii) Method of oil sampling (flow proportional, continuous drip, as delivered, or manual);

(iv) Mass of oil combusted each hour (lb/hr, rounded to the nearest tenth);

(v) For units using volumetric oil flowmeters, density of oil (flag value if derived from missing data procedures);

(vi) Gross calorific value (heat content) of oil used to determine heat input (Btu/mass unit) (flag value if derived from missing data procedures);

(vii) Hourly heat input rate from oil, according to procedures in appendix F to this part (mmBtu/hr, to the nearest tenth); and

(viii) Fuel usage time for combustion of oil during the hour (rounded up to the nearest 15 minutes).

(2) For each hour when the unit is combusting gaseous fuel:

(i) Date and hour;

(ii) Hourly heat input rate from gaseous fuel according to procedures in appendix F to this part (mmBtu/hr, rounded to the nearest tenth);

(iii) Hourly flow rate of gaseous fuel (100 scfh) (flag value if derived from missing data procedures);

(iv) Gross calorific value (heat content) of gaseous fuel used to determine heat input (Btu/100 scf) (flag value if derived from missing data procedures);

(v) Heat input rate from gaseous fuel (mmBtu/hr, rounded to the nearest tenth);

(vi) Fuel usage time for combustion of gaseous fuel during the hour (rounded up to the nearest 15 minutes); and

(vii) F-factor (F_c=Carbon-based F-factor of 1040 scf CO_2/mmBtu for natural gas, or F_d=Dry basis, O_2-based F-factor of 8,710 dscf/mmBtu for natural gas).

(3) For each oil sample or sample of diesel fuel:

(i) Date of sampling;

(ii) Gross calorific value or heat content (Btu/lb) (flag value if derived from missing data procedures);

(iii) Density or specific gravity, if required to convert volume to mass (flag value if derived from missing data procedures); and

(iv) Percent carbon by weight.

(4) For each monthly sample of gaseous fuel:

(i) Date of sampling; and

(ii) Gross calorific value or heat content (Btu/100 scf) (flag value if derived from missing data procedures).

(5) Hourly average diluent gas concentration (percent O_2 or percent CO_2, rounded to the nearest tenth).

(h) *Compliance dates.* Beginning on January 1, 2000, the owner or operator shall comply with this section only. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.55; except that if a regulatory option provided in another section of this part 75 is exercised prior to January 1, 2000, then the owner or operator shall comply with any provisions of this section that support the regulatory option beginning with the date on which the option is exercised.

40. Section 75.59 is added to read as follows:

§ 75.59 Certification, quality assurance, and quality control record provisions.

(a) *Continuous emission or opacity monitoring systems.* The owner or

operator shall record the applicable information in this section for each certified monitor or certified monitoring system (including certified backup monitors) measuring and recording emissions or flow from an affected unit.

(1) For each SO_2 or NO_X pollutant concentration monitor, flow monitor, CO_2 monitor (including O_2 monitors used to determine CO_2 emissions), moisture sensor, or diluent gas monitor (including wet-and dry-basis O_2 monitors used to determine percent moisture), the owner or operator shall record the following for all daily and 7-day calibration error tests, including any follow-up tests after corrective

(i) Component/system identification code;

(ii) Instrument span and span scale;

(iii) Date and hour;

(iv) Reference value (i.e., calibration gas concentration or reference signal value, in ppm or other appropriate units);

(v) Observed value (monitor response during calibration, in ppm or other appropriate units);

(vi) Percent calibration error (rounded to the nearest tenth of a percent) (flag if using alternative performance specification for low emitters or differential pressure flow monitors);

(vii) Calibration gas level;

(viii) Test number and reason for test;

(ix) For 7-day calibration tests for certification or recertification, a certification from the cylinder gas vendor or CEMS vendor that calibration gas, as defined in § 72.2 of this chapter and appendix A to this part, was used to conduct calibration error testing;

(x) Description of any adjustments, corrective actions, or maintenance following test; and

(xi) For the qualifying test for off-line calibration, the owner or operator shall indicate whether the unit is off-line or on-line.

(2) For each flow monitor, the owner or operator shall record the following for all daily interference checks, including any follow-up tests after corrective action:

(i) Code indicating whether monitor passes or fails the interference check; and

(ii) Description of any adjustments, corrective actions, or maintenance following test.

(3) For each SO_2 or NO_X pollutant concentration monitor, CO_2 monitor (including O_2 monitors used to determine CO_2 emissions), or diluent gas monitor (including wet-and dry-basis O_2 monitors used to determine percent moisture), the owner or operator shall record the following for the initial and all subsequent linearity check(s), including any follow-up tests after corrective action:

(i) Component/system identification code;

(ii) Instrument span and span scale;

(iii) Date and hour;

(iv) Reference value (i.e., reference gas concentration, in ppm or other appropriate units);

(v) Observed value (average monitor response at each reference gas concentration, in ppm or other appropriate units);

(vi) Percent error at each of three reference gas concentrations (rounded to nearest tenth of a percent) (flag if using alternative performance specification);

(vii) Calibration gas level;

(viii) Mean of reference values and mean of measured values;

(ix) Test number and reason for test (flag if aborted test); and

(x) Description of any adjustments, corrective action, or maintenance following test.

(4) For each flow monitor (where applicable) the owner or operator shall record items in paragraphs (a)(4)(i) through (v) of this section, for all quarterly leak checks, including any follow-up tests after corrective action, and items in paragraphs (a)(4)(vi) and (vii) of this section, for all flow-to-load ratio and gross heat rate tests:

(i) Component/system identification code;

(ii) Date and hour;

(iii) Reason for test;

(iv) Code indicating whether monitor passes or fails the quarterly leak check;

(v) Description of any adjustments, corrective actions, or maintenance following test;

(vi) Test data from the flow-to-load ratio or gross heat rate evaluation, including:

(A) Component/system identification code;

(B) Calendar year and quarter;

(C) Indication of whether the test is a flow-to-load ratio or gross heat rate evaluation;

(D) Indication of whether bias adjusted flow rates were used;

(E) Average absolute percent difference between reference ratio (or BHR) and hourly ratios (or GHE values);

(F) Test result;

(G) Number of hours used in final quarterly average;

(H) Number of hours exempted for use of a different fuel type;

(I) Number of hours exempted for load ramping up or down;

(J) Number of hours exempted for scrubber bypass;

(K) Number of hours exempted for hours preceding a normal-load flow RATA; and

(L) Number of hours exempted for hours preceding a successful diagnostic test, following a documented monitor repair or major component replacement; and

(vii) Reference data for the flow-to-load ratio or gross heat rate evaluation, including:

(A) Reference flow RATA end date and time;

(B) Test number;

(C) Reference RATA load and load level;

(D) Average reference method flow rate during reference flow RATA;

(E) Reference flow/load ratio;

(F) Average reference method diluent gas concentration during flow RATA and diluent gas units of measure;

(G) Fuel specific F_d- or F_c-factor during flow RATA and F-factor units of measure; and

(H) Reference gross heat rate value.

(5) For each SO_2 pollutant concentration monitor, flow monitor, CO_2 pollutant concentration monitor (including any O_2 concentration monitor used to determine CO_2 mass emissions or heat input), NO_X continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, moisture monitoring system, and approved alternative monitoring system, the owner or operator shall record the following information for the initial and all subsequent relative accuracy test audits:

(i) Reference method(s) used;

(ii) Individual test run data from the relative accuracy test audit for the SO_2 concentration monitor, flow monitor, CO_2 pollutant concentration monitor, NO_X continuous emission monitoring system, SO_2-diluent continuous emission monitoring system, moisture monitoring system, or approved alternative monitoring systems, including:

(A) Date, hour, and minute of beginning of test run;

(B) Date, hour, and minute of end of test run;

(C) System identification code;

(D) Test number and reason for test;

(E) Operating load level (low, mid, high, or normal, as appropriate) and number of load levels comprising test;

(F) Run number;

(G) Run data for monitor, in the appropriate units of measure;

(H) Run data for reference method, in the appropriate units of measure;

(I) Flag value (0, 1, or 9, as appropriate) indicating whether run has been used in calculating relative accuracy and bias values or whether the test was aborted prior to completion;

(J) Average gross unit load; and

(K) Flag to indicate whether an alternative performance specification has been used.

(iii) Calculations and tabulated results, as follows:

(A) Arithmetic mean of the monitoring system measurement values, of the reference method values, and of their differences, as specified in Equation A–7 in appendix A to this part.

(B) Standard deviation, as specified in Equation A–8 in appendix A to this part.

(C) Confidence coefficient, as specified in Equation A–9 in appendix A to this part.

(D) Relative accuracy test results, as specified in Equation A–10 in appendix A to this part. (For multi-level flow monitor tests the relative accuracy test results shall be recorded at each load level tested. Each load level shall be expressed as a total gross unit load, rounded to the nearest MWe, or as steam load, rounded to the nearest thousand lb/hr.)

(E) Bias test results as specified in section 7.6.4 in appendix A to this part.

(F) Bias adjustment factor from Equations A–11 and A–12 in appendix A to this part for any monitoring system that failed the bias test (except as provided in section 7.6.5 of appendix A to this part) and 1.000 for any monitoring system that passed the bias test. (For multi-load RATAs of flow monitors only, when the bias test is passed at the load level(s) designated as normal in section 6.5.2.1 of appendix A to this part, the system BAF shall be recorded as 1.000. When the bias test is failed at any load level designated as normal in section 6.5.2.1 of appendix A to this part, bias adjustment factors shall be recorded at the two most frequently used load levels, as defined in section 6.5.2.1 of appendix A to this part.)

(iv) Description of any adjustment, corrective action, or maintenance following test.

(v) F-factor value(s) used to convert NO_X pollutant concentration and diluent gas (O_2 or CO_2) concentration measurements into NO_X emission rates (in lb/mmBtu), heat input or CO_2 emissions.

(vi) For flow monitors, the flow polynomial equation used to linearize the flow monitor and the numerical values of the polynomial coefficients of that equation.

(6) For each SO_2, NO_X, CO_2, or O_2 pollutant concentration monitor, NO_X-diluent continuous emission monitoring system, or SO_2-diluent continuous emission monitoring system, the owner or operator shall record the following information for the cycle time test:

(i) Component/system identification code;

(ii) Date;

(iii) Start and end times;

(iv) Upscale and downscale cycle times for each component;

(v) Stable start monitor value;

(vi) Stable end monitor value;

(vii) Reference value of calibration gas(es);

(viii) Calibration gas level; and

(ix) Cycle time result for the entire system.

(x) Reason for test.

(7) The owner or operator shall also record, for each relative accuracy test audit, supporting information sufficient to substantiate compliance with all applicable sections and appendices in this part. This RATA supporting information shall include, but shall not be limited to, the following data elements:

(i) For each RATA using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter to determine volumetric flow rate:

(A) Information indicating whether or not the location meets requirements of Method 1 in appendix A to part 60 of this chapter; and

(B) Information indicating whether or not the equipment passed the required leak checks.

(ii) For each run of each RATA using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter to determine volumetric flow rate, record the following data elements (as applicable to the measurement method used):

(A) Operating load level (low, mid, high, or normal, as appropriate);

(B) Number of reference method traverse points;

(C) Average absolute stack gas temperature (° F);

(D) Barometric pressure at test port (inches of mercury);

(E) Stack static pressure (inches of H_2O);

(F) Absolute stack gas pressure (inches of mercury);

(G) Percent CO_2 and O_2 in the stack gas, dry basis;

(H) CO_2 and O_2 reference method used;

(I) Moisture content of stack gas (percent H_2O);

(J) Molecular weight of stack gas, dry basis (lb/lb-mole);

(K) Molecular weight of stack gas, wet basis (lb/lb-mole);

(L) Stack diameter (or equivalent diameter) at the test port (ft);

(M) Average square root of velocity head of stack gas (inches of H_2O) for the run;

(N) Stack or duct cross-sectional area at test port (ft^2);

(O) Average axial velocity (ft/sec); and

(P) Total volumetric flow rate (scfh, wet basis).

(iii) For each traverse point of each run of each RATA using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter to determine volumetric flow rate, record the following data elements (as applicable to the measurement method used):

(A) Reference method probe type;

(B) Pressure measurement device type;

(C) Traverse point ID;

(D) Probe or pitot tube calibration coefficient;

(E) Date of latest probe or pitot tube calibration;

(F) ΔP at traverse point (inches of H_2O);

(G) T_s, stack temperature at the traverse point (° F);

(H) Calculated impact (total) velocity at the traverse point (ft/sec);

(I) Composite (wall effects) traverse point identifier;

(J) Number of points included in composite traverse point;

(K) Yaw angle of flow at traverse point (degrees);

(L) Pitch angle of flow at traverse point (degrees); and

(M) Calculated axial velocity at traverse point (ft/sec).

(iv) For each RATA using Method 6C, 7E, or 3A in appendix A to part 60 of this chapter to determine SO_2, NO_X, CO_2, or O_2 concentration:

(A) Pollutant or diluent gas being measured;

(B) Span of reference method analyzer;

(C) Type of reference method system (e.g., extractive or dilution type);

(D) Reference method dilution factor (dilution type systems, only);

(E) Reference gas concentrations (zero, mid, and high gas levels) used for the 3-point pre-test analyzer calibration error test (or for dilution type reference method systems, for the 3-point pre-test system calibration error test) and for any subsequent recalibrations;

(F) Analyzer responses to the zero-, mid-, and high-level calibration gases during the 3-point pre-test analyzer (or system) calibration error test and during any subsequent recalibration(s);

(G) Analyzer calibration error at each gas level (zero, mid, and high) for the 3-point pre-test analyzer (or system) calibration error test and for any subsequent recalibration(s) (percent of span value);

(H) Reference gas concentration (zero, mid, or high gas levels) used for each pre-run or post-run system bias check or (for dilution type reference method

systems) for each pre-run or post-run system calibration error check;

(I) Analyzer response to the calibration gas for each pre-run or post-run system bias (or system calibration error) check;

(J) The arithmetic average of the analyzer responses to the zero-level gas, for each pair of pre- and post-run system bias (or system calibration error) checks;

(K) The arithmetic average of the analyzer responses to the upscale calibration gas, for each pair of pre-and post-run system bias (or system calibration error) checks;

(L) The results of each pre-run and each post-run system bias (or system calibration error) check using the zero-level gas (percentage of span value);

(M) The results of each pre-run and each post-run system bias (or system calibration error) check using the upscale calibration gas (percentage of span value);

(N) Calibration drift and zero drift of analyzer during each RATA run (percentage of span value);

(O) Moisture basis of the reference method analysis;

(P) Moisture content of stack gas, in percent, during each test run (if needed to convert to moisture basis of CEMS being tested);

(Q) Unadjusted (raw) average pollutant or diluent gas concentration for each run;

(R) Average pollutant or diluent gas concentration for each run, corrected for calibration bias (or calibration error) and, if applicable, corrected for moisture;

(S) The F-factor used to convert reference method data to units of lb/mmBtu (if applicable);

(T) The code for the formula used to convert reference method data to units of lb/mmBtu (if applicable);

(U) Date(s) of the latest analyzer interference test(s);

(V) Results of the latest analyzer interference test(s);

(W) Date of the latest NO_2 to NO conversion test (Method 7E only);

(X) Results of the latest NO_2 to NO conversion test (Method 7E only); and

(Y) For each calibration gas cylinder during each RATA, record the cylinder gas vendor, cylinder number, expiration date, pollutant(s) in the cylinder, and certified gas concentration(s).

(v) For each test run of each moisture determination using Method 4 in appendix A to part 60 of this chapter (or its allowable alternatives), whether the determination is made to support a gas RATA, to support a flow RATA, or to quality assure the data from a continuous moisture monitoring system, record the following data elements (as applicable to the moisture measurement method used):

(A) Parameter (SO_2, NO_X, flow, CO_2, or H_2O), to indicate whether the moisture determination is used to support a gas or flow rate RATA or whether the determination is used to quality assure a moisture monitoring system;

(B) Test number;

(C) Run number;

(D) The beginning date, hour, and minute of the run;

(E) The ending date, hour, and minute or the run;

(F) Unit operating level (low, mid, high, or normal, as appropriate);

(G) Moisture measurement method;

(H) Volume of H_2O collected in the impingers (ml);

(I) Mass of H_2O collected in the silica gel (g);

(J) Dry gas meter calibration factor;

(K) Average dry gas meter temperature (°F);

(L) Barometric pressure (inches of mercury);

(M) Differential pressure across the orifice meter (inches of H_2O);

(N) Initial and final dry gas meter readings (ft^3);

(O) Total sample gas volume, corrected to standard conditions (dscf); and

(P) Percentage of moisture in the stack gas (percent H_2O).

(vi) The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of appendix A to this part) for the unit or common stack on which the continuous emission monitor(s) are installed, expressed in megawatts or thousands of lb/hr of steam;

(vii) The load level(s) designated as normal in section 6.5.2.1 of appendix A to this part for the unit or common stack on which the continuous emission monitor(s) are installed, expressed in megawatts or thousands of lb/hr of steam;

(viii) Except for peaking units, the two load levels (i.e., low, mid, or high) identified in section 6.5.2.1 of appendix A to this part as the most frequently used;

(ix) Except for peaking units, the relative frequency (percentage) of historical usage of each load level (low, mid, and high) in the previous four QA operating quarters, as determined in section 6.5.2.1 of appendix A to this part, to the nearest 0.1 percent. The beginning and ending calendar quarters in the historical look-back period shall also be recorded. A summary of the data used to determine the most frequently and second most frequently used load levels and the percentage of time that each load level has been used historically shall be kept on-site in a format suitable for inspection;

(x) Indication of whether the unit/stack qualifies for single load flow RATA testing (operation for ≥ 85.0 percent of operating hours is at a single load level); and

(xi) Date of the load analysis described in paragraphs (a)(7)(vi) through (a)(7)(x) of this section.

(8) For each certified continuous emission monitoring system, continuous opacity monitoring system, or alternative monitoring system, the date and description of each event which requires recertification of the system and the date and type of each test performed to recertify the system in accordance with § 75.20(b).

(9) Hardcopy quality assurance relative accuracy test reports, certification reports, or recertification reports for pollutant concentration or stack flow CEMS shall include, as a minimum, the following elements (as applicable to the type(s) of test(s) performed):

(i) Summarized test results near the front of the report;

(ii) DAHS printouts of the CEMS data generated during the calibration error, linearity, cycle time, and relative accuracy tests;

(iii) For pollutant concentration monitor relative accuracy tests at normal operating load:

(A) The raw reference method data from each run (usually in the form of a computerized printout, showing a series of one-minute readings and the run average);

(B) The raw data and results for all required pre-test and post-test quality assurance checks (i.e., calibration gas injections) of the reference method analyzers;

(C) The raw data and results for any moisture measurements made during the relative accuracy testing;

(D) Tabulated, final, corrected reference method run data (i.e., the actual values used in the relative accuracy calculations), along with the equations used to convert the raw data to the final values and example calculations to demonstrate how the test data were reduced;

(iv) For flow monitor relative accuracy tests:

(A) The raw Reference Method 2 data, including auxiliary moisture data (often in the form of handwritten data sheets);

(B) The tabulated, final volumetric flow rate values used in the relative accuracy calculations (determined from the Method 2 data and other necessary measurements, e.g., moisture, stack temperature and pressure, etc.), along

with the equations used to convert the raw data to the final values and example calculations to demonstrate how the test data were reduced;

(v) Calibration gas certificates for the gases used in the linearity, calibration error, and cycle time tests and for the calibration gases used to quality assure the gas monitor reference method data during the relative accuracy test audit;

(vi) Laboratory calibrations of the source sampling equipment;

(vii) A copy of the test protocol used for the CEMS certifications or recertifications, including narrative that explains any testing abnormalities, problematic sampling, and analytical conditions that required a change to the test protocol, and/or solutions to technical problems encountered during the testing program;

(viii) Diagrams illustrating test locations and sample point locations (to verify that locations are consistent with presented information in the monitoring plan). Include a discussion of any special traversing or measurement scheme. The discussion shall also confirm that sample points satisfied applicable acceptance criteria; and

(ix) Names of key personnel involved in the test program, including test team members, plant contacts, agency representatives or test observers on site, etc.

(10) Whenever reference methods are used as backup monitoring systems pursuant to § 75.20(d)(3), the owner or operator shall record the following information:

(i) For each test run using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter to determine volumetric flow rate, record the following data elements (as applicable to the measurement method used):

(A) Unit or stack identification number;

(B) Reference method system and component identification numbers;

(C) Run date and hour;

(D) The data elements in paragraph (a)(7)(ii) of this section, except for paragraphs (a)(7)(ii) (A), (F), (H), and (L);

(E) Data element in paragraph (a)(7)(iii)(A) of this section.

(ii) For each reference method test run using Method 6C, 7E, or 3A in appendix A to part 60 of this chapter to determine SO_2, NO_X, CO_2, or O_2 concentration:

(A) Unit or stack identification number;

(B) The reference method system and component identification numbers;

(C) Run number;

(D) Run start date and hour;

(E) Run end date and hour;

(F) Data elements in paragraph (a)(7)(iv) (B) through (I) and (L) through (O) of this section; and

(G) Stack gas density adjustment factor (if applicable).

(iii) For each hour of each reference method test run using Method 6C, 7E, or 3A in appendix A to part 60 of this chapter to determine SO_2, NO_X, CO_2, or O_2 concentration:

(A) Unit or stack identification number;

(B) The reference method system and component identification numbers;

(C) Run number;

(D) Run date and hour;

(E) Pollutant or diluent gas being measured;

(F) Unadjusted (raw) average pollutant or diluent gas concentration for the hour; and

(G) Average pollutant or diluent gas concentration for the hour, adjusted as appropriate for moisture, calibration bias (or calibration error) and stack gas density.

(11) For each other quality-assurance test or other quality assurance activity, the owner or operator shall record the following:

(i) Component/system identification code;

(ii) Parameter;

(iii) Test or activity completion date and hour;

(iv) Test or activity description;

(v) Test result;

(vi) Reason for test;

(vii) Test code.

(12) For each quality assurance test extension or exemption request, the owner or operator shall record the following:

(i) For a RATA deadline extension or exemption request:

(A) Monitoring system identification code;

(B) Date of last RATA;

(C) RATA expiration date without extension;

(D) RATA expiration date with extension;

(E) Type of RATA extension of exemption claimed or lost;

(F) Year to date hours of fuel usage with a sulfur content >0.05 percent by weight; and

(G) Year to date hours of non-redundant back-up CEMS use at the unit/stack.

(ii) For a linearity test quarterly exemption:

(A) Component/system identification code; and

(B) Basis for exemption.

(iii) For a quality assurance test extension claim based on a grace period:

(A) Component/system identification code;

(B) Type of test;

(C) Beginning of grace period;

(D) Date and hour of completion of required quality assurance test or maximum allowable grace period if no quality assurance test was completed during the grace period; and

(E) Number of unit/stack operating hours from the beginning of the grace period to the completion of the quality assurance test or the maximum allowable grace period.

(13) An indication of which data have been excluded from the quarterly span and range evaluations of the SO_2 and NO_X monitors and the reasons for excluding the data, as required in sections 2.1.1.5 and 2.1.2.5 of appendix A to this part. For purposes of reporting under § 75.64(a)(1), this information shall be reported with the quarterly report as descriptive text consistent with § 75.64(g).

(b) *Excepted monitoring systems for gas-fired and oil-fired units.* The owner or operator shall record the applicable information in this section for each excepted monitoring system following the requirements of appendix D to this part or appendix E to this part for determining and recording emissions from an affected unit.

(1) For each oil-fired unit or gas-fired unit using the optional procedures of appendix D to this part for determining SO_2 mass emissions and/or heat input or the optional procedures of appendix E to this part for determining NO_X emission rate, for certification and quality assurance testing of fuel flowmeters tested against a reference fuel flow rate (i.e., flow rate another fuel flowmeter under section 2.1.5.2 of appendix D to this part or flow rate from a procedure according to a standard incorporated by reference under section 2.1.5.1 of appendix D to this part):

(i) Date and hour of test completion;

(ii) Upper range value of the fuel flowmeter;

(iii) Flowmeter measurements during accuracy test (and mean of values), including units of measure;

(iv) Reference flow rates during accuracy test (and mean of values), including units of measure;

(v) Average flowmeter accuracy as a percent of upper range value for low, mid, and high fuel flowrates;

(vi) Indicator of whether test method was a lab comparison to reference meter or an in-line comparison against a master meter;

(vii) Test result (aborted, pass, or fail);

(viii) Component and system identification numbers of the fuel flowmeter being tested;

(ix) Date and hour fuel flowmeter was reinstalled (only for tests not performed inline); and

(x) Description of fuel flowmeter calibration specification or procedure (in the certification application, or periodically if a different method is used for annual quality assurance testing).

(2) For each transmitter or transducer accuracy test for an orifice-, nozzle-, or venturi-type flowmeter used under section 2.1.6 of appendix D to this part:

(i) Date of test;

(ii) Full-scale value of the transmitter or transducer;

(iii) Transmitter input (pre-calibration) prior to accuracy test, including units of measure;

(iv) Expected transmitter output during accuracy test (reference value from NIST-traceable equipment), including units of measure;

(v) Actual transmitter output during accuracy test, including units of measure;

(vi) Transmitter or transducer accuracy as a percent of the full-scale value;

(vii) Transmitter output level as a percent of the full-scale value);

(viii) Transmitter or transducer accuracy, as a percent of full-scale value, and overall accuracy (if applicable), as a percent of upper range value;

(ix) Test and run number;

(x) Time of run (only for tests against another flowmeter inline);

(xi) Component and system identification numbers of the fuel flowmeter being tested;

(xii) Transmitter or transducer type (differential pressure, static pressure, or temperature); and

(xiii) Test result.

(3) For each visual inspection of the primary element or transmitter or transducer accuracy test for an orifice-, nozzle-, or venturi-type flowmeter under sections 2.1.6.1 through 2.1.6.6 of appendix D to this part:

(i) Date of inspection/test;

(ii) Hour of completion of inspection/test;

(iii) Component and system identification numbers of the fuel flowmeter being inspected/tested; and

(iv) Results of inspection/test (pass or fail).

(4) For fuel flowmeters that are tested using the flow-to-load ratio procedures of section 2.1.7 of appendix D to this part:

(i) Test data for the fuel flowmeter flow-to-load ratio or gross heat rate check, including:

(A) Component/system identification code;

(B) Calendar year and quarter;

(C) Indication of whether the test is for flow-to-load ratio or gross heat rate;

(D) Test result;

(E) Number of hours excluded due to co-firing;

(F) Number of hours excluded due to ramping;

(G) Number of hours excluded for lower 10.0 percent range of operation; and

(H) Quarterly average absolute percent difference between baseline ratio (or baseline GHR) and hourly quarterly ratios (or GHR value).

(ii) Reference data for the fuel flowmeter flow-to-load ratio or gross heat rate evaluation, including:

(A) Completion date and hour of most recent primary element inspection;

(B) Completion date and hour of most recent flowmeter or transmitter accuracy test;

(C) Beginning and hour of baseline period;

(D) Completion date and hour of baseline period;

(E) Average fuel flow rate;

(F) Average load;

(G) Baseline fuel flow-to-load ratio and fuel flow-to-load units of measure;

(H) Baseline GHR and GHR units;

(I) Number of hours excluded due to ramping; and

(J) Number of hours excluded in lower 10.0 percent of range of operation.

(5) For gas-fired peaking units or oil-fired peaking units using the optional procedures of appendix E to this part, for each initial performance, periodic, or quality assurance/quality control-related test:

(i) For each run of emission data;

(A) Run start date and time;

(B) Run end date and time;

(C) Fuel flow rate (lb/hr, gal/hr, scf/hr, bbl/hr, or m^3/hr);

(D) Gross calorific value (heat content) of fuel (Btu/lb or Btu/scf);

(E) Density of fuel, and units of measure for fuel density (if needed to convert mass to volume);

(F) Total heat input during the run (mmBtu);

(G) Hourly heat input rate for run (mmBtu/hr);

(H) Response time of the O2 and NO_X reference method analyzers;

(I) NO_X concentration (ppm);

(J) O_2 concentration (percent O_2);

(K) NO_X emission rate (lb/mmBtu);

(L) Fuel or fuel combination (by heat input fraction) combusted;

(M) Run number;

(N) Operating level;

(O) Elapsed time;

(P) Test number;

(Q) Monitoring system identification code for appendix E system, and oil or fuel flow system;

(R) Heat input from oil and/or gas during the run;

(S) Volumetric flow of oil and/or gas during the run, and units of measure for volumetric flow; and

(T) Mass fuel flow during the run.

(ii) For each unit load and heat input:

(A) Average NO_X emission rate (lb/mmBtu);

(B) F-factor used in calculations;

(C) Average heat input rate (mmBtu/hr);

(D) Unit operating parametric data related to NO_X formation for that unit type (e.g., excess O_2 level, water/fuel ratio);

(E) Fuel or fuel combination (by heat input fraction) combusted;

(F) Completion date and time of last run in level; and

(G) Arithmetic mean of reference method values at this level.

(c) For units with add-on SO_2 and NO_X emission controls following the provisions of § 75.34(a)(1) or (a)(2), the owner or operator shall keep the following records on-site in the quality assurance/quality control plan required by section 1 in appendix B to this part:

(1) A list of operating parameters for the add-on emission controls, including parameters in § 75.55(b), appropriate to the particular installation of add-on emission controls; and

(2) The range of each operating parameter in the list that indicates the add-on emission controls are properly operating.

(d) *Excepted flow monitoring systems under appendix I.* The owner or operator shall record the applicable information in this section for each certified excepted flow monitoring system under appendix I to this part measuring and recording flow from an affected unit.

(1) *Certification test records.* Record the results of the following tests:

(i) For each CO_2 or O_2 component monitor:

(A) 7-day calibration error tests, as specified in paragraph (a)(1) of this section;

(B) Cycle time test, as specified in paragraph (a)(6) of this section; and

(C) Linearity checks, as specified in paragraph (a)(3) of this section.

(ii) For each appendix I flow monitoring system tested in a component by component assessment:

(A) Flowmeter accuracy test data (or a statement of calibration, if the flowmeter meets the accuracy standard by design), as specified in paragraph (b)(1) of this section;

(B) Relative accuracy test and bias data for the CO_2 (or O_2) monitor, as specified in paragraphs (a)(5) and (a)(7) of this section; and

(C) Fuel sampling and analysis data, as specified in section 2.3 of appendix I to this part.

(iii) For each appendix I flow monitoring system tested in a system relative accuracy assessment:

(A) Relative accuracy test and bias data for the appendix I flow monitoring system, as specified for a flow monitoring system in paragraphs (a)(5) and (a)(7) of this section; and

(B) Fuel sampling and analysis data, as specified in section 2.3 of appendix I to this part.

(2) *Quality assurance/quality control test records.* Record the results of the following tests:

(i) For CO_2 or O_2 monitors:

(A) Daily calibration error tests, as specified in paragraph (a)(1) of this section; and

(B) Quarterly linearity checks, as specified in paragraph (a)(3) of this section.

(ii) For each appendix I flow monitoring system tested in a component-by-component assessment:

(A) Flowmeter accuracy test data, as specified in paragraph (b)(1) or (b)(2) of this section and paragraph (b)(3) or (b)(4) of this section;

(B) Relative accuracy test and bias data for the CO_2 (or O_2) monitor, as specified in paragraphs (a)(5) and (a)(7) of this section; and

(C) Fuel sampling and analysis data, as specified in section 2.3 of appendix I to this part.

(iii) For each appendix I flow monitoring system tested in a system relative accuracy assessment:

(A) Relative accuracy test and bias data for the appendix I flow monitoring system, as specified for a flow monitoring system in paragraphs (a)(5) and (a)(7) of this section; and

(B) Fuel sampling and analysis data, as specified in section 2.3 of appendix I to this part.

(e) *Compliance dates.* Beginning on January 1, 2000, the owner or operator shall comply with this section only. Before January 1, 2000, the owner or operator shall comply with either this section or § 75.56; except that if a regulatory option provided in another section of this part 75 is exercised prior to January 1, 2000, then the owner or operator shall comply with any provisions of this section that support the regulatory option beginning with the date on which the option is exercised.

41. Section 75.60 is amended by revising paragraphs (a), (b)(1), and (b)(2) and by adding new paragraphs (b)(3), (b)(4), (b)(5) and (b)(6) to read as follows:

§ 75.60 General provisions.

(a) The designated representative for any affected unit subject to the requirements of this part shall comply with all reporting requirements in this section and with the requirements of § 72.21 of this chapter for all submissions.

(b) * * *

(1) *Initial certifications.* The designated representative shall submit initial certification applications according to § 75.63.

(2) *Recertifications.* The designated representative shall submit recertification applications according to § 75.63.

(3) *Monitoring plans.* The designated representative shall submit monitoring plans according to § 75.62.

(4) *Electronic quarterly reports.* The designated representative shall submit electronic quarterly reports according to § 75.64.

(5) *Other petitions and communications.* The designated representative shall submit petitions, correspondence, application forms, designated representative signature, and petition-related test results in hardcopy to the Administrator. Additional petition requirements are specified in §§ 75.66 and 75.67.

(6) *Quality assurance RATA reports.* If requested by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit the quality assurance RATA report within 45 days after completing a quality assurance RATA according to section 2.3.1 of appendix B to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by § 75.59(a)(10) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the RATA report.

* * * * *

42. Section 75.61 is amended by revising paragraphs (a) introductory text, (a)(1) introductory text, and (b) and by adding a new paragraph (a)(1)(iv) to read as follows:

§ 75.61 Notifications.

(a) *Submission.* The designated representative for an affected unit (or owner or operator, as specified) shall submit notice to the Administrator, to the appropriate EPA Regional Office, and to the applicable State and local air pollution control agencies for the following purposes, as required by this part.

(1) *Initial certification and recertification test notifications.* The owner or operator or designated representative for an affected unit shall submit written notification of initial certification tests, recertification tests, and revised test dates as specified in § 75.20 for continuous emission monitoring systems, for alternative monitoring systems under subpart E of this part, or for excepted monitoring systems under appendix E or I to this part, except as provided in paragraphs (a)(1)(iv) and (a)(4) of this section and except for testing only of the data acquisition and handling system.

* * * * *

(iv) *Waiver from notification requirements.* The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may issue a waiver from the requirement of paragraph (a)(1) of this section to provide it for a unit or a group of units for one or more recertification tests. The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may also discontinue the waiver and enforce the requirement of paragraph (a)(1) of this section to provide it notice of recertification testing for future tests for a unit or a group of units.

* * * * *

(b) The owner or operator or designated representative shall submit notification of certification tests and recertification tests for continuous opacity monitoring systems as specified in § 75.20(c)(8) to the State or local air pollution control agency.

* * * * *

43. Section 75.62 is amended by revising paragraphs (a) and (c) to read as follows:

§ 75.62 Monitoring plan.

(a) *Submission.*—(1) *Electronic.* Using the format specified in paragraph (c) of this section, the designated representative for an affected unit shall submit a complete, electronic, up-to-date monitoring plan file (except for hardcopy portions identified in paragraph (a)(2) of this section) to the Administrator: No later than 45 days prior to the initial certification test; at the time of recertification application submission; and in each electronic quarterly report.

(2) *Hardcopy.* The designated representative shall submit all of the hardcopy information required under § 75.53 to the appropriate EPA Regional Office and the appropriate State and/or local air pollution control agency prior to initial certification. Thereafter, the

designated representative shall submit hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information: no later than 45 days prior to the initial certification test; with any recertification application, if a hardcopy monitoring plan change is associated with the recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to § 75.53(b).

* * * * *

(c) *Format.* Each monitoring plan shall be submitted in a format specified by the Administrator.

44. Section 75.63 is revised to read as follows:

§ 75.63 Initial certification or recertification application.

(a) *Submission.* The designated representative for an affected unit or a combustion source shall submit applications and reports as follows:

(1) *Initial certifications.* (i) Within 45 days after completing all initial certification tests, submit to the Administrator the electronic information required by paragraph (b)(1) of this section and a hardcopy certification application form (EPA form 7610–14). Except for subpart E applications or unless specifically requested by the Administrator, do not submit a hardcopy of the test data and results to the Administrator.

(ii) Within 45 days after completing all initial certification tests, submit the hardcopy information required by paragraph (b)(2) of this section to the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency.

(iii) For units for which the owner or operator is applying for certification approval of the optional excepted methodology under § 75.19 for low mass emissions units, submit:

(A) To the Administrator, the electronic information required by paragraph (b)(1)(i) of this section, the hardcopy information required by paragraph (b)(3) of this section, and a hardcopy certification application form (EPA form 7610–14) signed by the designated representative.

(B) To the applicable EPA Regional Office and appropriate State and/or local air pollution control agency, the hardcopy information required by paragraphs (b)(2)(i), (iii), and (iv) of this section and by paragraph (b)(3) of this section.

(2) *Recertifications.* (i) Within 45 days after completing all recertification tests, submit to the Administrator the electronic information required by (b)(1) of this section and a hardcopy certification application form (EPA form 7610–14). Except for subpart E applications or unless specifically requested by the Administrator, do not submit a hardcopy of the test data and results to the Administrator.

(ii) Within 45 days after completing all recertification tests, submit the hardcopy information required by paragraph (b)(2) of this section to the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency. The applicable EPA Regional Office or appropriate State or local air pollution control agency may waive the requirement for submission to it of a hardcopy recertification. The applicable EPA Regional Office or the appropriate State or local air pollution control agency may also discontinue the waiver and enforce the requirement of this paragraph (a)(2)(ii) to provide a hardcopy report of the recertification test data and results.

(iii) Notwithstanding the requirements of paragraphs (a)(2)(i) and (a)(2)(ii) of this section, for an event for which the Administrator determines that only diagnostic tests (see § 75.20(b)) are required rather than a RATA, an accuracy test of the fuel flowmeter, or a retest of the appendix E NO_X correlation curve, no hardcopy submittal of any kind is required; however, the results of all diagnostic test(s) shall be submitted in the electronic quarterly report required under § 75.64. For DAHS (missing data and formula) verifications, neither a hardcopy nor an electronic submittal of any kind is required; these test results shall be kept on-site, suitable for inspection.

(b) *Contents.* Each application for initial certification or recertification shall contain the following information, as applicable:

(1) *Electronic.* (i) A complete, up-to-date version of the electronic portion of the monitoring plan, according to § 75.53(c) and (d), or § 75.53(e) and (f), as applicable, in the format specified in § 75.62(c).

(ii) The results of the test(s) required by § 75.20, including the type of test conducted, testing date, information required by § 75.56 or § 75.59, as applicable, and the results of any failed tests that affect data validation.

(2) *Hardcopy.* (i) Any changed portions of the hardcopy monitoring plan information required under § 75.53(c) and (d), or § 75.53(e) and (f), as applicable.

(ii) The results of the test(s) required by § 75.20, including the type of test conducted, testing date, information required by § 75.59(a)(10), and the results of any failed tests that affect data validation.

(iii) Certification or recertification application form (EPA form 7610–14).

(iv) Designated representative signature.

(3) If the owner or operator is applying to use the optional low mass emissions excepted methodology in § 75.19(c) in lieu of a certified monitoring system,

(i) A statement that the unit burns only natural gas or fuel oil and a list of the fuels that are burned or a statement that the unit is projected to burn only natural gas or fuel oil and a list of the fuels that are projected to be burned;

(ii) A statement that the unit meets the applicability requirements in § 75.19(a) and (b); and

(iii) Any unit historical actual and projected emissions data and calculated emissions data demonstrating that the affected unit qualifies as a low mass emissions unit under § 75.19(a) and (b).

(c) *Format.* The electronic portion of each certification or recertification application shall be submitted in a format to be specified by the Administrator. The hardcopy test results shall be submitted in a format suitable for review and shall include the information in § 75.59(a)(10).

45. Section 75.64 is amended by revising paragraphs (a) introductory text, (d), and (e); by redesignating existing paragraphs (a)(1), (a)(2), (a)(3), (a)(4), (a)(5), and (a)(6) as paragraphs (a)(2), (a)(3), (a)(4), (a)(5),(a)(6) and (a)(8), respectively; by revising newly designated paragraphs (a)(2), and (a)(4); by adding new paragraphs (a)(1), (a)(7), (a)(9), (f), and (g); and by removing the third sentence in paragraph (c), to read as follows:

§ 75.64 Quarterly reports.

(a) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in paragraphs (a), (b), and (c) of this section to the Administrator quarterly, beginning with the data from the later of: the last (partial) calendar quarter of 1993 (where the calendar quarter data begins at November 15, 1993), the calendar quarter corresponding to the date of provisional certification, or the calendar quarter corresponding to the relevant deadline for initial certification in § 75.4(a), (b), or (c), whichever quarter is earlier (where the report contains hourly data beginning with the hour of provisional certification or the hour corresponding to the relevant certification deadline, whichever is earlier). For an affected unit subject to

§ 75.4(d) that is shutdown on the relevant compliance date in § 75.4(a), the owner or operator shall submit quarterly reports for the unit beginning with the data from the quarter in which the owner or operator recommences commercial operation of the unit (where the report contains hourly data beginning with the first hour of recommenced commercial operation of the unit). For any provisionally-certified monitoring system, § 75.20(a)(3) shall apply for initial certifications, and § 75.20(b)(5) shall apply for recertifications. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Each electronic report shall include the date of report generation, for the information provided in paragraphs (a)(2) through (a)(9) of this section, and shall also include for each affected unit (or group of units using a common stack):

(1) Facility information:

(i) Identification, including:

(A) Facility/ORISPL number;

(B) Calendar quarter and year data contained in the report; and

(C) EDR version used for the report.

(ii) Location, including:

(A) Plant name and facility ID;

(B) EPA AIRS facility system ID;

(C) State facility ID;

(D) Source category/type;

(E) Primary SIC code;

(F) State postal abbreviation;

(G) County code; and

(H) Latitude and longitude.

(2) The information and hourly data required in §§ 75.53 through 75.59, excluding:

(i) Descriptions of adjustments, corrective action, and maintenance;

(ii) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);

(iii) Opacity data listed in § 75.54(f) or § 75.57(f), and in § 75.59(a)(9);

(iv) For units with SO_2 or NO_X add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in § 75.55(b)(3) or § 75.58(b)(3);

(v) The information recorded under § 75.56(a)(7) for the period prior to January 1, 2000;

(vi) Information required by § 75.54(g) or § 75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes; and

(vii) Hardcopy monitoring plan information required by § 75.53 and hardcopy test data and results required by § 75.56 or § 75.59;

(viii) Records of flow polynomial equations and numerical values required by § 75.56(a)(5)(vii) or § 75.59(a)(5)(vi);

(ix) Daily fuel sampling information required by § 75.58(c)(3)(i) for units using assumed values under appendix D;

(x) Information required by §§ 75.59(b)(1)(ii), (iii), (iv), and (x), and (b)(2) concerning fuel flowmeter accuracy tests and transmitter/transducer accuracy tests;

(xi) Stratification test results required as part of the RATA supplementary records under §§ 75.56(a)(7) or 75.59(a)(7);

(xii) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to operational problems with the unit; and

(xiii) The summary of data used to determine the percentage of historical usage of each load level as required under § 75.59(a)(8)(iv).

(xiv) Supplementary RATA information required under §§ 75.59(a)(7)(iv)(A), (U), (V), (W), (X), and (Y).

* * * * *

(4) Average NO_X emission rate (lb/mmBtu, rounded to the nearest hundredth prior to January 1, 2000 and to the nearest thousandth on and after January 1, 2000) during the quarter and cumulative NO_X emission rate for the calendar year.

* * * * *

(7) Unit/stack/pipe operating hours for quarter and cumulative unit/stack/pipe operating hours for calendar year.

* * * * *

(9) For low mass emissions units for which the owner or operator is using the optional low mass emissions methodology in § 75.19(c) to calculate NO_X mass emissions, the designated representative must also report tons (rounded to the nearest tenth) of NO_X emitted during the quarter and cumulative NO_X mass emissions for the calendar year.

* * * * *

(d) *Electronic format.* Each quarterly report shall be submitted in a format to be specified by the Administrator, including both electronic submission of data and electronic or hardcopy submission of compliance certifications.

(e) *Phase I qualifying technology reports.* In addition to reporting the information in paragraphs (a), (b), and (c) of this section, the designated representative for an affected unit on which SO_2 emission controls have been installed and operated for the purpose of meeting qualifying Phase I technology requirements pursuant to § 72.42 of this chapter shall also submit reports documenting the measured percent SO_2 emissions removal to the Administrator on a quarterly basis, beginning the first quarter of 1997 and continuing through the fourth quarter of 1999. Each report shall include all measurements and calculations necessary to substantiate that the qualifying technology achieves the required percent reduction in SO_2 emissions.

(f) *Method of submission.* Beginning with the quarterly report for the first quarter of the year 2000, all quarterly reports shall be submitted to EPA by direct computer-to-computer electronic transfer via modem and EPA-provided software, unless otherwise approved by the Administrator.

(g) Any cover letter text accompanying a quarterly report shall either be submitted in hardcopy to the Agency or be provided in electronic format compatible with the other data required to be reported under this section.

46. Section 75.65 is revised to read as follows:

§ 75.65 Opacity reports.

The owner or operator or designated representative shall report excess emissions of opacity recorded under § 75.54(f) or § 75.57(f), as applicable, to the applicable State or local air pollution control agency.

47. Section 75.66 is amended by revising paragraphs (a) and the first sentence of (e) introductory text; by redesignating paragraph (i) as paragraph (m) and revising it; and by adding paragraphs (i) through (l), to read as follows:

§ 75.66 Petitions to the Administrator.

(a) *General.* The designated representative for an affected unit subject to the requirements of this part may submit a petition to the Administrator requesting that the Administrator exercise his or her discretion to approve an alternative to any requirement prescribed in this part or incorporated by reference in this part. Any such petition shall be submitted in accordance with the requirements of this section. The designated representative shall comply with the signatory requirements of § 72.21 of this chapter for each submission.

* * * * *

(e) *Parametric monitoring procedure petitions.* The designated representative for an affected unit may submit a petition to the Administrator, where each petition shall contain the information specified in § 75.55(b) or

§ 75.58(b), as applicable, for the use of a parametric monitoring method. * * * * * * * * *

(i) *Emergency fuel petition.* The designated representative for an affected unit may submit a petition to the Administrator to use the emergency fuel provisions in Section 2.1.4 of Appendix E of this part. The designated representative shall include the following information in the petition:

(1) Identification of the affected unit(s);

(2) A procedure for determining the NO_X emission rate for the unit when the emergency fuel is combusted; and

(3) A demonstration that the permit restricts use of the fuel to emergencies only.

(j) *Petition for alternative method of accounting for emissions prior to completion of certification tests.* The designated representative for an affected unit may submit a petition to the Administrator to use an alternative to the procedures in § 75.4 (d)(3), (e)(3), (f)(3) and/or (g)(3) to account for emissions during the period between the compliance date for a unit and the completion of certification testing for that unit. The designated representative shall include:

(1) Identification of the affected unit(s);

(2) A detailed explanation of the alternative method to account for emissions of the following parameters, as applicable: SO_2 mass emissions (in lbs), NO_X emission rate (in lbs/mmbtu), CO_2 mass emissions (in lbs) and, if the unit is subject to the requirements of subpart H of this part, NO_X mass emissions (in lbs); and

(3) A demonstration that the proposed alternative does not underestimate emissions.

(k) *Petition for an alternative to the stabilization criteria for the cycle time test in section 6.4 of Appendix A of this part.* The designated representative for an affected unit may submit a petition to the Administrator to use an alternative stabilization criteria for the cycle time test in section 6.4 of Appendix A of this part, if the installed monitoring system does not record data in 1-minute or 3-minute intervals. The designated representative shall provide a description of the alternative criteria.

(l) *Petition for an alternative to the maximum rated hourly heat input used to determine emissions under the low mass emissions excepted methodology in § 75.19.* The designated representative for an affected unit may submit a petition to the Administrator to use an alternative to the maximum rated hourly heat input to determine emissions under the low mass emissions excepted methodology set forth in § 75.19. The designated representative shall provide the following information:

(1) Identification of the affected unit(s);

(2) Information demonstrating that the maximum rated hourly heat input, as defined in § 72.2 of this chapter, is not representative of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently; and

(3) Information documenting that the proposed alternative maximum heat input is representative of the unit's highest potential heat input.

(m) *Any other petitions to the Administrator under this part.* Except for petitions addressed in paragraphs (b) through (l) of this section, any petition submitted under this paragraph shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:

(1) Identification of the affected unit(s);

(2) A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;

(3) A description and diagram of any equipment and procedures used in the proposed alternative, if applicable;

(4) A demonstration that the proposed alternative is consistent with the purposes of the requirement for which the alternative is proposed and is consistent with the purposes of this part and of section 412 of the Act and that any adverse effect of approving such alternative will be *de minimis;* and

(5) Any other relevant information that the Administrator may require.

48. Subpart H is added to read as follows:

Subpart H—NO_X Mass Emissions Provisions

Sec.
75.70 NO_X mass emissions provisions.
75.71 Specific provisions for monitoring NO_X emission rate and heat input for the purpose of calculating NO_X mass emissions.
75.72 Determination of NO_X mass emissions.
75.73 Recordkeeping and reporting.

Subpart H—NO_X Mass Emissions Provisions

§ 75.70 NO_X mass emissions provisions.

(a) The owner or operator of a unit shall comply with the requirements of this subpart only if such compliance is required by an applicable state or federal NO_X mass emission reduction program that incorporates by reference, or otherwise adopts the requirements of, this subpart. For purposes of this subpart, the term ''affected unit'' shall mean any unit that is subject to a state or federal NO_X mass emission reduction program requiring compliance with this subpart, the term ''nonaffected unit'' shall mean any unit that is not subject to such a program, the term ''permitting authority'' shall mean the permitting authority under an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term ''designated representative'' shall mean the responsible party under the applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart. In addition, as set forth in this subpart, the provisions of subparts A, C, D, E, F, and G and appendices A through G applicable to NO_X emission rate and heat input shall apply to the owner or operator of a unit required to meet the requirements of this subpart by a state or federal NO_X mass emission reduction program, except that the term ''affected unit'' shall mean any unit that is subject to a state or federal NO_X mass emission reduction program requiring compliance with this subpart, the term ''permitting authority'' shall mean the permitting authority under an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart, and the term ''designated representative'' shall mean the responsible party under the applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(b) *Compliance dates.* The owner or operator of an affected unit shall meet the compliance deadlines established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(c) *Prohibitions.* (1) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall use any alternative monitoring system, alternative reference method, or any other alternative for the required continuous emission monitoring system without having obtained prior written approval in accordance with paragraph (g) of this section.

(2) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall operate the unit so as to discharge, or allow to be discharged emissions of NO_X to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this part.

(3) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall disrupt the continuous emission monitoring system, any portion thereof, or any other

approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this part.

(4) No owner or operator of an affected unit or a non-affected unit under § 75.72(b)(2)(ii) shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved emission monitoring system under this part, except under any one of the following circumstances:

(i) During the period that the unit is covered by a retired unit exemption under § 96.5 that is in effect;

(ii) The owner or operator is monitoring NO_X mass emissions from the affected unit with another certified monitoring system approved, in accordance with the provisions of paragraph (d) of this section; or

(iii) The designated representative submits notification of the date of certification testing of a replacement monitoring system in accordance with § 75.73(d)(5).

(d) *Initial certification and recertification procedures.* (1) The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures of this part except that:

(i) The owner or operator shall meet any additional requirements set forth in an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(ii) For any additional NO_X emission rate CEMS required under the common stack provisions in § 75.72, the owner or operator shall meet the requirements of paragraph (d)(2) of this section.

(2) The owner or operator of an affected unit that is not subject to an Acid Rain emissions limitation shall comply with the initial certification and recertification procedures established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart. The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation shall, for any additional NO_X emission rate CEMS required under the common stack provisions in § 75.72, comply with the initial certification and recertification procedures established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(e) *Quality assurance and quality control requirements.* The owner or operator shall meet the quality assurance and quality control requirements in § 75.21.

(f) *Missing data procedures.* Except as provided in § 75.34, the owner or operator shall provide substitute data for each affected unit and each non-affected unit under § 75.72(b)(2)(ii) using a continuous emissions monitoring system in accordance with the missing data procedures in subpart D of this part whenever the unit combusts fuel and:

(1) A valid quality assured hour of NO_X emission rate data (in lb/mmBtu) has not been measured and recorded for an affected unit or non-affected unit under § 75.72(b)(2)(ii) by a certified NO_X continuous emission monitoring system or by an approved monitoring system under subpart E of this part;

(2) A valid quality assured hour of flow data (in scfh) has not been measured and recorded for an affected unit or non-affected unit under § 75.72(b)(2)(ii) from a certified flow monitor or by an approved alternative monitoring system under subpart E of this part; or

(3) A valid quality assured hour of heat input data (in mmBtu) has not been measured and recorded for an affected unit from a certified flow monitor and a certified diluent (CO_2 or O_2) monitor or by an approved alternative monitoring system under subpart E of this part or by an accepted monitoring system under appendix D to this part.

(g) *Petitions.* (1) The owner or operator of an affected unit that is subject to an Acid Rain emissions limitation may submit a petition to the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart. Use of an alternative to any requirement of this subpart is in accordance with this subpart and with such state or federal NO_X mass emission reduction program only to the extent that the petition is approved by the Administrator, in consultation with the permitting authority.

(2) Notwithstanding paragraph (g)(1) of this section, petitions requesting an alternative to a requirement concerning any additional CEMS required solely to meet the common stack provisions of § 75.72, shall be submitted to the permitting authority and the Administrator and shall be governed by paragraph (g)(3)(ii) of this section. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(3)(i) The owner or operator of an affected unit that is not subject to an Acid Rain emissions limitation may submit a petition to the permitting authority and the Administrator requesting an alternative to any requirement of this subpart. Such a petition shall meet the requirements of § 75.66 and any additional requirements established by an applicable state or federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(ii) Use of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that it is approved by both the permitting authority and the Administrator.

§ 75.71 Specific provisions for monitoring NO_X emission rate and heat input for the purpose of calculating NO_X mass emissions.

(a) *Coal-fired units.* The owner or operator of an affected unit shall meet the general operating requirements in § 75.10 for a NO_X continuous emission monitoring system (including a NO_X pollutant concentration monitor and an O_2- or CO_2-diluent gas monitor) to measure NO_X emission rate and for a continuous flow monitoring system and an O_2- or CO_2-diluent gas monitor to measure heat input, except as provided by the Administrator in accordance with subpart E of this part.

(b) *Moisture correction.* If a correction for the stack gas moisture content is needed to properly calculate the NO_X emission rate in lb/mmBtu (i.e., if the NO_X pollutant concentration monitor measures on a different moisture basis from the diluent monitor), the owner or operator of an affected unit shall install, operate, maintain, and quality assure a continuous moisture monitoring system, as defined in § 75.11(b).

(c) *Gas-fired nonpeaking units or oil-fired non-peaking units.* The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit but not as a peaking unit, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan shall either:

(1) Meet the requirements of paragraph (a) of this section and, if applicable, paragraph (b) of this section; or

(2) Meet the general operating requirements in § 75.10 for a NO_X continuous emission monitoring system, except as provided, where applicable, in paragraph (e)(2) of this section or by the

Administrator in accordance with subpart E of this part, and use the procedures specified in appendix D to this part for determining hourly heat input. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart.

(d) *Peaking units that combust natural gas or fuel oil.* The owner or operator of an affected unit that combusts only natural gas or fuel oil and that qualifies as a peaking unit, as defined in § 72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan shall either:

(1) Meet the requirements of paragraph (c) of this section; or

(2) Use the procedures in appendix D to this part for determining hourly heat input and the procedure specified in appendix E to this part for estimating hourly NO_X emission rate. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart. In addition, if after certification of an excepted monitoring system under appendix E to this part, a unit's operations exceed a capacity factor of 20.0 percent in any calender year or exceed a capacity factor of 10.0 percent averaged over three years, the owner or operator shall meet the requirements of paragraph (c) of this section or, if applicable, paragraph (e) of this section by no later than December 31 of the following calender year.

(e) *Low mass emissions units.* Notwithstanding the requirements of paragraphs (c) and (d) of this section, the owner or operator of an affected unit that qualifies as a low mass emissions unit under § 75.19(a) shall comply with one of the following:

(1) Meet the applicable requirements specified in paragraph (c) or (d) of this section for monitoring NO_X emission rate and heat input; or

(2) Use the low mass emissions excepted methodology in § 75.19(c) for estimating hourly emission rate, hourly heat input, and hourly NO_X mass emissions.

(f) *Other units.* The owner or operator of an affected unit that combusts wood, refuse, or other materials shall comply with the monitoring provisions specified in paragraph (a) of this section and, where applicable, paragraph (b) of this section.

§ 75.72 Determination of NO_X mass emissions.

The owner or operator of an affected unit shall calculate hourly NO_X mass emissions (in lbs) by multiplying the hourly NO_X emission rate (in lbs/mmBtu) by the hourly heat input (in mmBtu/hr) and the hourly operating time (in hr). The owner or operator shall also calculate quarterly and cumulative year-to-date NO_X mass emissions and cumulative NO_X mass emissions for the ozone season (in tons) by summing the hourly NO_X mass emissions according to the procedures in section 8 of appendix F to this part.

(a) *Unit utilizing common stack with other affected unit(s).* When an affected unit utilizes a common stack with one or more affected units, but no nonaffected units, the owner or operator shall either:

(1) Record the combined NO_X mass emissions for the units exhausting to the common stack, install, certify, operate, and maintain a NO_X continuous emissions monitoring system in the common stack and:

(i) Install, certify, operate, and maintain a continuous flow monitoring system at the common stack; or

(ii) If all of the units using the common stack are eligible to use the procedures in appendix D to this part, use the procedures in appendix D to this part to determine heat input for each affected unit and use the combined heat input of all of the units exhausting to the common stack for calculating NO_X mass emissions; however, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart; or

(2) Install, certify, operate, and maintain a NO_X continuous emissions monitoring system in the duct to the common stack from each affected unit and:

(i) Install, certify, operate, and maintain a flow monitor in the duct to the common stack from each affected unit; or

(ii)(A) For any unit using the common stack and eligible to use the procedures in appendix D to this part, use the procedures in appendix D to determine heat input for that affected unit. However, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the mass reporting provisions of this subpart; and

(B) Install, certify, operate, and maintain a flow monitor in the duct to the common stack for each remaining affected unit.

(b) *Unit utilizing common stack with nonaffected unit(s).* When one or more affected units utilizes a common stack with one or more nonaffected units, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X continuous emission monitoring system in the duct to the common stack from each affected unit; and

(i) Install, certify, operate, and maintain a continuous flow monitoring system in the duct to the common stack from each affected unit; or

(ii)(A) For any unit using the common stack and eligible to use the procedures in appendix D to this part, use the procedures in appendix D to determine heat input for that affected unit; however, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the mass reporting provisions of this subpart; and

(B) Install, certify, operate, and maintain a flow monitor in the duct to the common stack for each remaining affected unit that exhausts to the common stack; or

(2) Install, certify, operate, and maintain a NO_X continuous emission monitoring system in the common stack; and

(i) Designate the nonaffected units as affected units in accordance with the applicable state or federal NO_X mass emissions reduction program and meet the requirements of paragraph (a)(1) of this section; or

(ii)(A) Install, certify, operate, and maintain a continuous flow monitoring system in the common stack and a NO_X continuous emission monitoring system in the duct to the common stack from each nonaffected unit and either install, certify, operate, and maintain a continuous flow monitoring system in the duct from each nonaffected unit or, for any nonaffected unit exhausting to the common stack and otherwise eligible to use the procedures in appendix D to this part, determine heat input using the procedures in appendix D for that nonaffected unit (however, the heat input apportionment provisions in section 2.1.2 of appendix D to this part shall not be used to meet the NO_X mass reporting provisions of this subpart), and for any remaining nonaffected unit that exhausts to the common stack, install, certify, operate, and maintain a flow monitor in the duct to the common stack; and

(B) Submit a petition to the permitting authority and the Administrator to allow a method of calculating and reporting the NO_X mass emissions from the affected units as the difference between NO_X mass emissions measured in the common stack and NO_X mass emissions measured in the ducts of the nonaffected units, not to be reported as an hourly value less than zero. The permitting authority and the

Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated; or

(iii) Install a continuous flow monitoring system in the common stack and record the combined emissions from all units as the combined NO_X mass emissions for the affected units for recordkeeping and compliance purposes; or

(iv) Submit a petition to the permitting authority and the Administrator to allow use of a method for apportioning NO_X mass emissions measured in the common stack to each of the units using the common stack and for reporting the NO_X mass emissions. The permitting authority and the Administrator may approve such a method whenever the designated representative demonstrates, to the satisfaction of the permitting authority and the Administrator, that the method ensures that the NO_X mass emissions from the affected units are not underestimated.

(c) *Unit with bypass stack.* Whenever any portion of the flue gases from an affected unit can be routed to avoid the installed NO_X continuous emissions monitoring system, the owner and operator shall either:

(1) Install, certify, operate, and maintain a NO_X continuous emissions monitoring system and a continuous flow monitoring system on the bypass flue, duct, or stack gas stream and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by all required monitoring systems; or

(2) Monitor NO_X mass emissions on the bypass flue, duct, or stack gas stream using the reference methods in § 75.22(b) for NO_X concentration, flow, and diluent and calculate NO_X mass emissions for the unit as the sum of the emissions recorded by the installed monitoring systems on the main stack and the emissions measured by the reference method monitoring systems.

(d) *Unit with multiple stacks.* Notwithstanding § 75.17(c), when the flue gases from an affected unit utilize two or more ducts feeding into two or more stacks (which may include flue gases from other affected or nonaffected unit(s)), or when the flue gases from an affected unit utilize two or more ducts feeding into a single stack and the owner or operator chooses to monitor in the ducts rather than in the stack, the owner or operator shall either:

(1) Install, certify, operate, and maintain a NO_X continuous emission monitoring system and a continuous flow monitoring system in each duct feeding into the stack or stacks and determine NO_X mass emissions from each affected unit using the stack or stacks as the sum of the NO_X mass emissions recorded for each duct; or

(2) Install, certify, operate, and maintain a NO_X continuous emissions monitoring system and a continuous flow monitoring system in each stack, and determine NO_X mass emissions from the affected unit using the sum of the NO_X mass emissions recorded for each stack, except that where another unit also exhausts flue gases to one or more of the stacks, the owner or operator shall also comply with the applicable requirements of paragraphs (a) and (b) of this section to determine and record NO_X mass emissions from the units using that stack; or

(3) If the unit is eligible to use the procedures in appendix D to this part, install, certify, operate, and maintain a NO_X continuous emissions monitoring system in one of the ducts feeding into the stack or stacks and use the procedures in appendix D to this part to determine heat input for the unit, provided that:

(i) There are no add-on NO_X controls at the unit;

(ii) The unit is not capable of emitting solely through an unmonitored stack (i.e., has no dampers); and

(iii) The owner or operator of the unit demonstrates to the satisfaction of the permitting authority and the Administrator that the NO_X emission rate in the monitored duct or stack is representative of the NO_X emission rate in each duct or stack.

§ 75.73 Recordkeeping and reporting.

(a) *General recordkeeping provisions.* The owner or operator of any affected unit shall maintain for each affected unit and each non-affected unit under § 75.72(b)(2)(ii) a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Except for the certification data required in § 75.57(a)(4) and the initial submission of the monitoring plan required in § 75.57(a)(5), the data shall be collected beginning with the earlier of the date of provisional certification or the deadline in § 75.70. The certification data required in § 75.57(a)(4) shall be collected beginning with the date of the first certification test performed.

The file shall contain the following information:

(1) The information required in §§ 75.57(a)(2), (a)(4), (a)(5), (a)(6), (b), (c)(2), (d), (g), and (h);

(2) The information required in §§ 75.58 (b), (d), and (g);

(3) For each hour when the unit is operating, NO_X mass emissions, calculated in accordance with section 8.1 of appendix F to this part;

(4) During the second and third calendar quarters, cumulative ozone season heat input and cumulative ozone season operating hours;

(5) Heat input and NO_X methodologies for the hour;

(6) *Specific heat input record provisions for gas-fired or oil-fired units using the procedures in appendix D to this part.* In lieu of the information required in § 75.57(c)(2), the owner or operator shall record the following information in this paragraph for each affected gas-fired or oil-fired unit and each non-affected gas-or oil-fired unit under § 75.72(b)(2)(ii) for which the owner or operator is using the procedures in appendix D to this part for estimating heat input:

(i) For each hour when the unit is combusting oil:

(A) Date and hour;

(B) Hourly average flow rate of oil, while the unit combusts oil (in gal/hr, lb/hr, m^3/hr, or bbl/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(C) Method of oil sampling (flow proportional, continuous drip, as delivered, manual from storage tank, or daily manual);

(D) Mass rate of oil combusted each hour (in lb/hr, rounded to the nearest tenth) (flag value if derived from missing data procedures);

(E) For units using volumetric oil flowmeters, density of oil (flag value if derived from missing data procedures);

(F) Gross calorific value (heat content) of oil used to determine heat input (in Btu/mass unit) (flag value if derived from missing data procedures);

(G) Hourly heat input rate from oil, according to procedures in appendix F to this part (in mmBtu/hr, to the nearest tenth);

(H) Fuel usage time for combustion of oil during the hour (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)) (flag to indicate multiple/single fuel types combusted); and

(I) Monitoring system identification code;

(ii) For gas-fired units or oil-fired units, using the procedures in appendix D to this part with an assumed density or for as-delivered fuel sampled from each delivery:

(A) Measured GCV and, if applicable, density from each fuel sample; and

(B) Assumed GCV and, if applicable, density used to calculate heat input rate;

(iii) For each hour when the unit is combusting gaseous fuel:

(A) Date and hour;

(B) Hourly heat input rate from gaseous fuel, according to procedures in appendix F to this part (in mmBtu/hr, rounded to the nearest tenth);

(C) Hourly flow rate of gaseous fuel, while the unit combusts gas (in 100 scfh) (flag value if derived from missing data procedures);

(D) Gross calorific value (heat content) of gaseous fuel used to determine heat input rate (in Btu/100 scf) (flag value if derived from missing data procedures);

(E) Heat input rate from gaseous fuel, while the unit combusts gas (in mmBtu/hr, rounded to the nearest tenth);

(F) Fuel usage time for combustion of gaseous fuel during the hour (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)) (flag to indicate multiple/single fuel types combusted); and

(G) Monitoring system identification code;

(iv) For each oil sample or sample of diesel fuel:

(A) Date of sampling;

(B) Gross calorific value or heat content (in Btu/lb) (flag value if derived from missing data procedures); and

(C) Density or specific gravity, if required to convert volume to mass (flag value if derived from missing data procedures);

(v) For each sample of gaseous fuel:

(A) Date of sampling; and

(B) Gross calorific value or heat content (in Btu/100 scf) (flag value if derived from missing data procedures);

(vi) For each oil sample or sample of gaseous fuel:

(A) Type of oil or gas; and

(B) Percent carbon or F-factor of fuel;

(7) *Specific NO_X, record provisions for gas-fired or oil-fired units using the optional low mass emissions excepted methodology in § 75.19.* In lieu of recording the information in § 75.57(b), (c)(2), (d), and (g), the owner or operator shall record, for each hour when the unit is operating for any portion of the hour, the following information for each affected low mass emissions unit for which the owner or operator is using the low mass emissions excepted methodology in § 75.19(c):

(i) Date and hour;

(ii) If one type of fuel is combusted in the hour, fuel type (pipeline natural gas, natural gas, residual oil, or diesel fuel) or, if more than one type of fuel is combusted in the hour, the fuel type which results in the highest emission factors for NO_X;

(iii) Average hourly NO_X emission rate (in lb/mmBtu, rounded to the nearest thousandth); and

(iv) Hourly NO_X mass emissions (in lbs, rounded to the nearest tenth).

(b) *Certification, quality assurance and quality control record provisions.* The owner or operator of any affected unit shall record the applicable information in § 75.59 for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii).

(c) *Monitoring plan record provisions.* (1) *General provisions.* The owner or operator of an affected unit shall prepare and maintain a monitoring plan for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii). Except as provided in paragraph (d) or (f) of this section, a monitoring plan shall contain sufficient information on the continuous emission monitoring systems, excepted methodology under § 75.19, or excepted monitoring systems under appendix D or E to this part and the use of data derived from these systems to demonstrate that all the unit's NO_X emissions are monitored and reported.

(2) Whenever the owner or operator makes a replacement, modification, or change in the certified continuous emission monitoring system, excepted methodology under § 75.19, excepted monitoring system under appendix D or E to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan.

(3) *Contents of the monitoring plan for units not subject to an Acid Rain emissions limitation.* Each monitoring plan shall contain the information in § 75.53(e)(1) in electronic format and the information in § 75.53(e)(2) in hardcopy format. In addition, to the extent applicable, each monitoring plan shall contain the information in § 75.53(f)(1)(i), (f)(2)(i), and (f)(4) in electronic format and the information in § 75.53(f)(1)(ii) and (f)(2)(ii) in hardcopy format.

(d) *General reporting provisions.* (1) The designated representative for an affected unit shall comply with all reporting requirements in this section and with any additional requirements set forth in an applicable state or Federal NO_X mass emission reduction program that adopts the requirements of this subpart.

(2) The designated representative for an affected unit shall submit the following for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii);

(i) Initial certification applications in accordance with § 75.70(d);

(ii) Monitoring plans in accordance with paragraph (e) of this section; and

(iii) Quarterly reports in accordance with paragraph (f) of this section.

(3) *Other petitions and communications.* The designated representative for an affected unit shall submit petitions, correspondence, application forms, and petition-related test results in accordance with the provisions in § 75.70(g).

(4) *Quality assurance RATA reports.* If requested by the permitting authority, the designated representative of an affected unit shall submit the quality assurance RATA report for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii) by the later of 45 days after completing a quality assurance RATA according to section 2.3 of appendix B to this part or 15 days of receiving the request. The designated representative shall report the hardcopy information required by § 75.59(a)(10) to the permitting authority.

(5) *Notifications.* The designated representative for an affected unit shall submit written notice to the permitting authority according to the provisions in § 75.61 for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii).

(e) *Monitoring plans.* (1) *Submission.*

(i) *Electronic.* The designated representative for an affected unit shall submit a complete, electronic, up-to-date monitoring plan file (except for hardcopy portions identified in paragraph (e)(1)(ii) of this section) for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii) as follows:

(A) To the permitting authority, no later than 45 days prior to the initial certification test and at the time of recertification application submission; and

(B) To the Administrator, no later than 45 days prior to the initial certification test, at the time of recertification application submission, and in each electronic quarterly report.

(ii) *Hardcopy.* The designated representative of an affected unit shall

submit all of the hardcopy information required under § 75.53, for each affected unit or group of units monitored at a common stack and each non-affected unit under § 75.72(b)(2)(ii), to the permitting authority prior to initial certification. Thereafter, the designated representative shall submit hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information: no later than 45 days prior to the initial certification test; with any recertification application, if a hardcopy monitoring plan change is associated with the recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to § 75.53(b).

(2) [Reserved]

(f) *Quarterly reports.* (1) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in this paragraph (f)(1) and in paragraphs (f)(2) and (3) of this section to the Administrator quarterly. Each electronic report shall include the date of report generation, for the information provided in paragraphs (f)(1)(ii) through (f)(1)(vi) of this section, and shall also include for each affected unit or group of units monitored at a common stack:

(i) Facility information:

(A) Identification, including:

(*1*) Facility/ORISPL number;

(*2*) Calendar quarter and year data contained in the report; and

(*3*) EDR version used for the report;

(B) Location, including:

(*1*) Plant name and facility ID;

(*2*) EPA AIRS facility system ID;

(*3*) State facility ID;

(*4*) Source category/type;

(*5*) Primary SIC code;

(*6*) State postal abbreviation;

(*7*) County code; and

(*8*) Latitude and longitude;

(ii) The information and hourly data required in paragraph (a) of this section, except for:

(A) Descriptions of adjustments, corrective action, and maintenance;

(B) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);

(C) For units with NO_X add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in § 75.58(b)(3);

(D) Information required by § 75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;

(E) Hardcopy monitoring plan information required by § 75.53 and hardcopy test data and results required by § 75.59;

(F) Records of flow polynomial equations and numerical values required by § 75.59(a)(5)(vi);

(G) Daily fuel sampling information required by § 75.58(c)(3)(i) for units using assumed values under appendix D;

(H) Information required by § 75.59(b)(2) concerning transmitter/transducer accuracy tests;

(I) Stratification test results required as part of the RATA supplementary records under § 75.56(a)(7) or § 75.59(a)(7);

(J) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to operational problems with the unit; and

(K) The summary of data used to determine the percentage of historical usage of each load level as required under § 75.59(a)(8)(iv);

(iii) Average NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth) during the quarter and cumulative NO_X emission rate for the calendar year;

(iv) Tons of NO_X emitted during quarter, cumulative tons of NO_X emitted during the year, and, during the second and third calender quarters, cumulative tons of NO_X emitted during the ozone season;

(v) During the second and third calender quarters, cummulative heat input for the ozone season; and

(vi) Unit/stack/pipe operating hours for quarter, cumulative unit/stack/pipe operating hours for calendar year, and, during the second and third calender quarters, cumulative operating hours during the ozone season.

(2) The designated representative shall affirm that the component/system identification codes and formulas in the quarterly electronic reports submitted to the Administrator pursuant to paragraph (e) of this section represent current operating conditions.

(3) *Compliance certification.* The designated representative shall submit and sign a compliance certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(i) The monitoring data submitted were recorded in accordance with the applicable requirements of this part, including the quality assurance procedures and specifications; and

(ii) With regard to a unit with add-on emission controls and for all hours where data are substituted in accordance with § 75.34(a)(1), the add-on emission controls were operating within the range of parameters listed in the monitoring plan and the substitute values do not systematically underestimate NO_X emissions.

(4) The designated representative shall comply with all of the quarterly reporting requirements in §§ 75.64(d), (f), and (g).

Appendix A to Part 75—Specifications and Test Procedures

Appendix A—[Amended]

49.–53. Appendix A to part 75 is amended by revising section 2.1 to read as follows:

* * * * *

2. Equipment Specifications

2.1 Instrument Span and Range

In implementing sections 2.1.1 through 2.1.5 of this appendix, set the measurement range for each parameter (SO_2, NO_X, CO_2, O_2, or flow rate) high enough to prevent full-scale exceedances from occurring, yet low enough to ensure good measurement accuracy and to maintain a high signal-to-noise ratio. To meet these objectives, it is recommended that the range be selected such that the readings obtained during typical unit operation are kept, to the extent practicable, between 20.0 and 80.0 percent of full-scale range of the instrument. Note that this guideline does not apply to: (1) SO_2 readings obtained during the combustion of natural gas or fuel with a total sulfur content no greater than the total sulfur content of natural gas; (2) SO_2 or NO_X readings recorded on the high measurement range, for units with SO_2 or NO_X emission controls and two span values; or (3) SO_2 or NO_X readings less than 20.0 percent of full-scale on the low measurement range for a dual span unit with SO_2 or NO_X emission controls, provided that the readings occur during periods of high control device efficiency.

2.1.1 SO_2 Pollutant Concentration Monitors

Determine, as indicated below, the span value(s) and range(s) for an SO_2 pollutant concentration monitor so that all potential and expected concentrations can be accurately measured and recorded. Note that if a unit exclusively combusts fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 0.05 percent sulfur by weight), the SO_2 monitor span requirements in § 75.11(e)(3)(iv) apply in lieu of the requirements of this section.

2.1.1.1 Maximum Potential Concentration

Make an initial determination of the maximum potential concentration (MPC) of SO_2 by using Equation A–1a or A–1b. Base the MPC calculation on the maximum percent sulfur and the minimum gross calorific value (GCV) for the highest-sulfur

fuel to be burned. The maximum sulfur content and minimum GCV shall be determined from all available fuel sampling and analysis data for that fuel from the previous 12 months (minimum), excluding clearly anomalous fuel sampling results. If the designated representative certifies that the highest-sulfur fuel is never burned alone in the unit during normal operation but is always blended or co-fired with other fuel(s), the MPC may be calculated using a best estimate of the highest sulfur content and lowest gross calorific value expected for the blend or fuel mixture and inserting these values into Equation A–1a or A–1b. Derive the best estimate of the highest percent sulfur and lowest GCV for a blend or fuel mixture from weighted-average values based upon the historical composition of the blend or mixture in the previous 12 (or more) months. If insufficient representative fuel sampling data are available to determine the maximum sulfur content and minimum GCV, use values from contract(s) for the fuel(s) that will be combusted by the unit in the MPC calculation.

Alternatively, if a certified SO_2 CEMS is already installed, the owner or operator may make the initial MPC determination based upon quality assured historical data recorded by the CEMS. If this option is chosen, the MPC shall be the maximum SO_2 concentration observed during the previous 720 (or more) quality assured monitor operating hours when combusting the highest-sulfur fuel (or highest-sulfur blend if fuels are always blended or co-fired) that is to be combusted in the unit or units monitored by the SO_2 monitor. For units with SO_2 emission controls, the certified SO_2 monitor used to determine the MPC must be located at or before the control device inlet. Report the MPC and the method of determination in the monitoring plan required under § 75.53.

When performing fuel sampling to determine the MPC, use ASTM Methods: ASTM D3177–89, ''Standard Test Methods for Total Sulfur in the Analysis Sample of Coal and Coke''; ASTM D4239–85, ''Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods''; ASTM D4294–90, ''Standard Test Method for Sulfur in Petroleum Products by Energy-Dispersive X-Ray Fluorescence Spectroscopy''; ASTM D1552–90, ''Standard Test Method for Sulfur in Petroleum Products (High Temperature Method)''; ASTM D129–91, ''Standard Test Method for Sulfur in Petroleum Products (General Bomb Method)''; ASTM D2622–92, ''Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry'' for sulfur content of solid or liquid fuels; ASTM D3176–89, ''Standard Practice for Ultimate Analysis of Coal and Coke''; ASTM D240–87 (Reapproved 1991), ''Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter''; or ASTM D2015–91, ''Standard Test Method for Gross Calorific Value of Coal and Coke by the Adiabatic Bomb Calorimeter'' for GCV (incorporated by reference under § 75.6).

$$\text{MPC (or MEC)} = 11.32 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{20.9 - \%O_{2w}}{20.9}\right)$$

(Eq. A–1a)

or

$$\text{MPC (or MEC)} = 66.93 \times 10^6 \left(\frac{\%S}{GCV}\right)\left(\frac{\%CO_{2w}}{100}\right)$$

(Eq. A–1b)

Where:

MPC=Maximum potential concentration (ppm, wet basis). To convert to dry basis, divide the MPC by 0.9).

MEC=Maximum expected concentration (ppm, wet basis). To convert to dry basis, divide the MEC by 0.9).

%S=Maximum sulfur content of the fuel to be fired, wet basis, weight percent, as determined by ASTM D3177–89, ASTM D4239–85, ASTM D4294–90, ASTM D1552–90, ASTM D129–91, or ASTM D2622–92 for solid or liquid fuels (incorporated by reference under § 75.6).

$\%O_{2w}$=Minimum oxygen concentration, percent wet basis, under typical operating conditions.

$\%CO_{2w}$=Maximum carbon dioxide concentration, percent wet basis, under typical operating conditions.

11.32×10^6=Oxygen-based conversion factor in (Btu/lb)(ppm)/%.

66.93×10^6=Carbon dioxide-based conversion factor in (Btu/lb)(ppm)/%.

Note: All percentage values to be inserted in the equations of this section are to be expressed as a percentage, not a fractional value (e.g., 3, not .03).

2.1.1.2 Maximum Expected Concentration

Make an initial determination of the maximum expected concentration (MEC) of SO_2 whenever: (a) SO_2 emission controls are used; or (b) both high-sulfur and low-sulfur fuels (e.g., high-sulfur coal and low-sulfur coal or different grades of fuel oil) or high-sulfur and low-sulfur fuel blends are combusted as primary or backup fuels in a unit without SO_2 emission controls. For units with SO_2 emission controls, use Equation A–2 to make the initial MEC determination. When high-sulfur and low-sulfur fuels or blends are burned as primary or backup fuels in a unit without SO_2 controls, use Equation A–1a or A–1b to calculate the initial MEC value for each fuel or blend, except for: (1) the highest-sulfur fuel or blend (for which the MPC was previously calculated in section 2.1.1.1 of this appendix); (2) fuels or blends with a total sulfur content no greater than the total sulfur content of natural gas, i.e., ≤ 0.05 percent sulfur by weight; or (3) fuels or blends that are used only for unit startup.

For each MEC determination, substitute into Equation A–1a or A–1b the highest sulfur content and minimum GCV value for that fuel or blend, based upon all available fuel sampling and analysis results from the previous 12 months (or more), or, if fuel sampling data are unavailable, based upon fuel contract(s).

Alternatively, if a certified SO_2 CEMS is already installed, the owner or operator may make the initial MEC determination(s) based upon historical monitoring data. If this option is chosen for a unit with SO_2 emission controls, the MEC shall be the maximum SO_2 concentration measured downstream of the control device outlet by the CEMS over the previous 720 (or more) quality assured monitor operating hours with the unit and the control device both operating normally. For units that burn high- and low-sulfur fuels or blends as primary and backup fuels and have no SO_2 emission controls, the MEC for each fuel shall be the maximum SO_2 concentration measured by the CEMS over the previous 720 (or more) quality assured monitor operating hours in which that fuel or blend was the only fuel being burned in the unit.

$$MEC = MPC\left(\frac{100 - RE}{100}\right)$$

(Eq. A–2)

where:

MEC=Maximum expected concentration (ppm).

MPC=Maximum potential concentration (ppm), as determined by Eq. A–1a or A–1b.

RE=Expected average design removal efficiency of control equipment (percent).

2.1.1.3 Span Value(s) and Range(s)

Determine the high span value and the high full-scale range of the SO_2 monitor as follows. (Note: For purposes of this part, the high span and range refer, respectively, either to the span and range of a single span unit or to the high span and range of a dual span unit.) The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25. Round the

span value upward to the next highest multiple of 100 ppm. If the SO_2 span concentration is ≤ 500 ppm, the span value may be rounded upward to the next highest multiple of 10 ppm, instead of the nearest 100 ppm. The high span value shall be used to determine concentrations of the calibration gases required for daily calibration error checks and linearity tests. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Report the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit. Note that for certain applications, a second (low) SO_2 span value may be required (see section 2.1.1.4 of this appendix). If an existing state, local, or federal requirement for span of an SO_2 pollutant concentration monitor requires a span lower than that required by this section or by section 2.1.1.4 of this appendix, the state, local, or federal span value may be used if a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix. Span values higher than those required by either this section or section 2.1.1.4 of this appendix must be approved by the Administrator.

2.1.1.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.1.3 of this appendix will suffice to measure and record SO_2 concentrations (unless span and/or range adjustments become necessary in accordance with section 2.1.1.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all possible or expected SO_2 concentrations. To determine whether two SO_2 span values are required, proceed as follows:

(a) For units with SO_2 emission controls, compare the MEC from section 2.1.1.2 of this appendix to the MPC value from section 2.1.1.1 of this appendix. If the MEC is ≥20.0 percent of the MPC, then the high span value and range determined under section 2.1.1.3 of this appendix are sufficient. If the MEC is < 20.0 percent of the MPC, however, a second (low) span value is required.

(b) For units that combust high- and low-sulfur primary and backup fuels (or blends) and have no SO_2 controls, compare the MPC value from section 2.1.1.1 of this appendix (for the highest-sulfur fuel or blend) to the MEC value for each of the other fuels or blends, as determined under section 2.1.1.2 of this appendix. If all of the MEC values are ≥20.0 percent of the MPC, the high span and range determined under section 2.1.1.3 of this appendix are sufficient, regardless of which fuel or blend is burned in the unit. If any MEC value is <20.0 percent of the MPC, however, a second (low) span value must be used when that fuel or blend is combusted.

(c) When two SO_2 spans are required, the owner or operator may either use a single SO_2 analyzer with a dual range (i.e., low- and high-scales) or two separate SO_2 analyzers connected to a common sample probe and sample interface. For units with SO_2 emission controls, the owner or operator may use a low range analyzer and a default high range value, as described in paragraph (f) of this section, in lieu of maintaining and quality assuring a high-scale range. Other monitor configurations are subject to the approval of the Administrator.

(d) The owner or operator shall designate the monitoring systems and components as follows: (1) designate the low and high monitor ranges as separate components of a single, primary monitoring system; or (2) designate the low and high monitor ranges as separate, primary monitoring systems; or (3) designate the normal monitor range as a primary monitoring system and the other monitor range as a non-redundant backup monitoring system; or (4) for units with SO_2 controls, if the default high range value is used, designate the low range analyzer as the primary monitoring system.

(e) Each monitoring system designated as primary shall meet the initial certification and quality assurance requirements for primary monitoring systems in § 75.20(c) and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for units with SO_2 emission controls, the low range is considered normal). Each monitoring system designated as a non-redundant backup shall meet the applicable quality assurance requirements in § 75.20(d).

(f) For dual span units with SO_2 emission controls, the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default SO_2 concentration of 200.0 percent of the MPC for each unit operating hour in which the full-scale of the low range SO_2 analyzer is exceeded.

(g) The high span value and range shall be determined in accordance with section 2.1.1.3 of this appendix. The low span value shall be obtained by multiplying the MEC by a factor no less than 1.00 and no greater than 1.25, and rounding the result upward to the next highest multiple of 10 ppm (or 100 ppm, as appropriate). For units that burn high- and low-sulfur primary and backup fuels or blends and have no SO_2 emission controls, select, as the basis for calculating the appropriate low span value and range, the fuel-specific MEC value closest to 20.0 percent of the MPC (from paragraph (b) of this section). The low range must be greater than or equal to the low span value, and the required calibration gases must be selected based on the low span value. For units with two SO_2 spans, use the low range whenever the SO_2 concentrations are expected to be consistently below 20.0 percent of the MPC, i.e., when the MEC of the fuel or blend being combusted is less than 20.0 percent of the MPC. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the SO_2 concentrations; or, if applicable, the default high range value in paragraph (f) of this section shall be reported for each hour of the full-scale exceedance.

2.1.1.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a quarterly evaluation of the MPC, MEC, span, and range values for each SO_2 monitor and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a) through (e), below. Span and range adjustments may be required as a result of changes in the fuel supply, changes in the manner of operation of the unit, installation or removal of emission controls, etc. In implementing the provisions in paragraphs (a) through (e), below, note that SO_2 data recorded during short-term, non-representative process operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from the analysis; however, if the high range is exceeded, 200.0 percent of the high range must still be reported as the hourly SO_2 concentration for each hour of the full-scale exceedance, as required by paragraph (c)(1) of this section. The owner or operator shall document all such unrepresentative operating conditions in the quarterly report required under § 75.64 and shall indicate which data (dates and hours) have been excluded from the quarterly span and range evaluation.

Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

(a) No span or range adjustment is required if, during a calendar quarter, the hourly SO_2 concentration exceeds the MPC but does not exceed the high span value. However, for missing data purposes, if any of the hourly SO_2 concentrations exceed the current MPC by ≥5.0 percent, a new MPC equal to the highest quality assured hourly SO_2 concentration recorded during the quarter must be defined in the monitoring plan. Update the monitoring plan to reflect the new MPC value.

(b) A span adjustment is required if any of the on-scale, quality assured hourly SO_2 concentrations exceed the high span value by ≤ 10.0 percent during a quarter, but do not exceed the high range. Define a new MPC value (as applicable) equal to the highest quality assured on-scale SO_2 concentration recorded during the quarter, and set the new span value according to section 2.1.1.3 of this appendix, using the new MPC value. If the new span value exceeds the current full-scale range, adjust the range setting also. Update the monitoring plan to reflect the new MPC, the new span value, and (if applicable) the new full-scale range. Where separate ranges are used to measure emissions from the combustion of different types of fuel, the low span and MEC shall be increased in the manner described in this paragraph if any on-scale hourly value exceeds the low span value by 10.0 percent or more.

(c) Whenever a full-scale range is exceeded during a quarter and the exceedance is not caused by a monitor out-of-control period, proceed as follows:

(1) For exceedances of the high range, report 200.0 percent of the current full-scale range as the hourly SO_2 concentration for

each hour of the full-scale exceedance and make adjustments to the MPC, span, and range to prevent future full-scale exceedances.

(2) For units with two SO_2 spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and is not out-of-control or out-of-service for any reason. However, if the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the SO_2 concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded follow the procedures in paragraph (c)(1) of this section).

(d) If the fuel supply, the composition of the fuel blend(s), the emission controls, or the manner of operation change such that the maximum expected or potential concentration changes significantly, adjust the span and range setting to assure the continued accuracy of the monitoring system. The owner or operator should evaluate whether any planned changes in operation of the unit may affect the concentration of emissions being emitted from the unit or stack and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. Determine the adjusted span(s) using the procedures in sections 2.1.1.3 and 2.1.1.4 of this appendix (as applicable). Select the full-scale range(s) of the instrument to be greater than or equal to the new span value(s) and to be consistent with the guidelines of section 2.1 of this appendix.

(e) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the SO_2 monitor, as described in paragraphs (a) through (d) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC and calculations of the adjusted span value in an updated monitoring plan. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check specified by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is so significant that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, then a diagnostic linearity test using the new calibration gases must be performed and passed. Data from the monitor are considered invalid from the hour in which the span is adjusted until the required linearity check is passed in accordance with section 6.2 of this appendix.

2.1.2 NO_X Pollutant Concentration Monitors

Determine, as indicated below, the span and range value(s) for the NO_X pollutant concentration monitor so that all expected NO_X concentrations can be determined and recorded accurately.

2.1.2.1 Maximum Potential Concentration

The maximum potential concentration (MPC) of NO_X for each affected unit shall be based upon whichever fuel or blend combusted in the unit produces the highest level of NO_X emissions. Make an initial determination of the MPC using the appropriate option below. Note that an initial MPC value determined for a unit that is not equipped with low-NO_X burners must be re-evaluated if a low-NO_X burner system is subsequently installed.

Option 1: Use 800 ppm for coal-fired and 400 ppm for oil-or gas-fired units as the maximum potential concentration of NO_X (if an MPC of 1600 ppm for coal-fired units or 480 ppm for oil-or gas-fired units was previously selected under this part, that value may still be used, provided that the guidelines of section 2.1 of this appendix are met);

Option 2: Use the specific values based on boiler type and fuel combusted, listed in Table 2–1 or Table 2–2;

Option 3: Use NO_X emission test results; or

Option 4: Use historical CEM data over the previous 720 (or more) unit operating hours when combusting the fuel or blend with the highest NO_X emission rate.

For the purpose of providing substitute data during NO_X missing data periods in accordance with §§ 75.31 and 75.33 and as required elsewhere under this part, the owner or operator shall also calculate the maximum potential NO_X emission rate (MER), in lb/mmBtu, by substituting the MPC for NO_X in conjunction with the minimum CO_2 or maximum O_2 concentration (under all unit operating conditions except for unit startup, shutdown, and upsets) and the appropriate F-factor into the applicable equation in appendix F to this part. The diluent cap value of 5.0 percent CO_2 (or 14.0 percent O_2) for boilers or 1.0 percent CO_2 (or 19.0 percent O_2) for combustion turbines may be used in the NO_X MER calculation.

Report the method of determining the initial MPC and the calculation of the maximum potential NO_X emission rate in the monitoring plan for the unit.

For units with add-on NO_X controls, NO_X emission testing may only be used to determine the MPC if testing can be performed on uncontrolled emissions (e.g., measured at or before the control device inlet). If NO_X emission testing is performed, use the following guidelines. Use Method 7E from appendix A to part 60 of this chapter to measure total NO_X concentration. (Note: Method 20 from appendix A to Part 60 may be used for gas turbines, instead of Method 7E.) Operate the unit, or group of units sharing a common stack, at the minimum safe and stable load, the normal load, and the maximum load. If the normal load and maximum load are identical, an intermediate level need not be tested. Operate at the highest excess O_2 level expected under normal operating conditions. Make at least three runs of 20 minutes (minimum) duration with three traverse points per run at each operating condition. Select the highest point NO_X concentration (e.g., the highest one-minute average) from all test runs as the MPC for NO_X.

If historical CEM data are used to determine the MPC, the data must represent a minimum of 720 quality assured monitor operating hours, obtained under various operating conditions, including the minimum safe and stable load, normal load (including periods of high excess air at normal load), and maximum load. For units with add-on NO_X controls, historical CEM data may only be used to determine the MPC if there are 720 quality assured monitor operating hours of CEM data measuring uncontrolled emissions (e.g., the CEM data are collected at or before the control device inlet). The highest hourly NO_X concentration in ppm shall be the MPC.

2.1.2.2 Maximum Expected Concentration

Make an initial determination of the maximum expected concentration (MEC) of NO_X during normal operation for affected units with add-on NO_X controls of any kind (i.e., steam injection, water injection, SCR, or SNCR). Determine a separate MEC value for each type of fuel (or blend) combusted in the unit, except for fuels that are only used for unit startup and/or flame stabilization. Calculate the MEC of NO_X using Equation A–2, if applicable, inserting the maximum potential concentration, as determined using the procedures in section 2.1.2.1 of this appendix. Where Equation A–2 is not applicable, set the MEC either by: (1) measuring the NO_X concentration using the testing procedures in this section; or (2) using historical CEM data over the previous 720 (or more) quality assured monitor operating hours. Include in the monitoring plan for the unit each MEC value and the method by which the MEC was determined.

If NO_X emission testing is used to determine the MEC value(s), the MEC for each type of fuel (or blend) shall be based upon testing at minimum load, normal load, and maximum load. At least three tests of 20 minutes (minimum) duration, using at least 3 traverse points, shall be performed at each load, using Method 7E from appendix A to part 60 of this chapter (Note: Method 20 from appendix A to part 60 may be used for gas turbines instead of Method 7E). The test must be performed at a time when all NO_X control devices and methods used to reduce NO_X emissions are operating properly. The testing shall be conducted downstream of all NO_X controls. The highest point NO_X concentration (e.g., the highest one-minute average) recorded during any of the test runs shall be the MEC.

If historical CEM data are used to determine the MEC value(s), the MEC for each type of fuel shall be based upon 720 (or more) hours of quality assured data representing the entire load range under stable operating conditions. The data base for the MEC shall not include any CEM data recorded during unit startup, shutdown, or malfunction or during any NO_X control device malfunctions or outages. All NO_X control devices and methods used to reduce

NO_X emissions must be operating properly during each hour. The CEM data shall be collected downstream of all NO_X controls. For each type of fuel, the highest of the 720 (or more) quality assured hourly average NO_X concentrations recorded by the CEMS shall be the MEC.

2.1.2.3 Span Value(s) and Range(s)

Determine the high span value of the NO_X monitor as follows. The high span value shall be obtained by multiplying the MPC by a factor no less than 1.00 and no greater than 1.25. Round the span value upward to the next highest multiple of 100 ppm. If the NO_X span concentration is ≤ 500 ppm, the span value may be rounded upward to the next highest multiple of 10 ppm, rather than 100 ppm. The high span value shall be used to determine the concentrations of the calibration gases required for daily calibration error checks and linearity tests. Note that for certain applications, a second (low) NO_X span value may be required (see section 2.1.2.4 of this appendix).

If an existing state, local, or federal requirement for span of an NO_X pollutant concentration monitor requires a span lower than that required by this section or by section 2.1.2.4 of this appendix, the state, local, or federal span value may be used, where a satisfactory explanation is included in the monitoring plan, unless span and/or range adjustments become necessary in accordance with section 2.1.2.5 of this appendix. Span values higher than required by this section or by section 2.1.2.4 of this appendix must be approved by the Administrator.

Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the high span value. Include the full-scale range setting and calculations of the MPC and span in the monitoring plan for the unit.

2.1.2.4 Dual Span and Range Requirements

For most units, the high span value based on the MPC, as determined under section 2.1.2.3 of this appendix will suffice to measure and record NO_X concentrations (unless span and/or range adjustments must be made in accordance with section 2.1.2.5 of this appendix). In some instances, however, a second (low) span value based on the MEC may be required to ensure accurate measurement of all expected and potential NO_X concentrations. To determine whether two NO_X spans are required, proceed as follows:

(a) Compare the MEC value(s) determined in section 2.1.2.2 of this appendix to the MPC value determined in section 2.1.2.1 of this appendix. If the MEC values for all fuels (or blends) are ≥ 20.0 percent of the MPC, the high span and range values determined under section 2.1.2.3 of this appendix are sufficient, irrespective of which fuel or blend is combusted in the unit. If any of the MEC values is < 20.0 percent of the MPC, two spans (low and high) are required, one based upon the MPC and the other based on the MEC.

(b) When two NO_X spans are required, the owner or operator may either use a single NO_X analyzer with a dual range (low-and high-scales) or two separate NO_X analyzers connected to a common sample probe and sample interface. For units with add-on NO_X emission controls (i.e., steam injection, water injection, SCR, or SNCR), the owner or operator may use a low range analyzer and a ''default high range value,'' as described in paragraph 2.1.2.4(e) of this section, in lieu of maintaining and quality assuring a high-scale range. Other monitor configurations are subject to the approval of the Administrator.

(c) The owner or operator shall designate the monitoring systems and components as follows: (1) designate the low and high ranges as separate components of a single, primary monitoring system; or (2) designate the low and high ranges as separate, primary monitoring systems; or (3) designate the normal range as a primary monitoring system and the other range as a non-redundant backup monitoring system; or (4) for units with add-on NO_X controls, if the default high range value is used, designate the low range analyzer as the primary monitoring system.

(d) Each monitoring system designated as primary shall meet the initial certification and quality assurance requirements for primary monitoring systems in § 75.20(c) and appendices A and B to this part, with one exception: relative accuracy test audits (RATAs) are required only on the normal range (for dual span units with add-on NO_X emission controls, the low range is considered normal). Each monitoring system designated as non-redundant backup shall meet the applicable quality assurance requirements in § 75.20(d).

(e) For dual span units with add-on NO_X emission controls (i.e., steam injection, water injection, SCR, or SNCR), the owner or operator may, as an alternative to maintaining and quality assuring a high monitor range, use a default high range value. If this option is chosen, the owner or operator shall report a default value of 200.0 percent of the MPC for each unit operating hour in which the full-scale of the low range NO_X analyzer is exceeded.

(f) The high span and range shall be determined in accordance with section 2.1.2.3 of this appendix. The low span value shall be 100.0 to 125.0 percent of the MEC, rounded up to the next highest multiple of 10 ppm (or 100 ppm, if appropriate). If more than one MEC value (as determined in section 2.1.2.2 of this appendix) is <20.0 percent of the MPC, the low span value shall be based upon whichever MEC value is closest to 20.0 percent of the MPC. The low range must be greater than or equal to the low span value, and the required calibration gases for the low range must be selected based on the low span value. For units with two NO_X spans, use the low range whenever NO_X concentrations are expected to be consistently <20.0 percent of the MPC, i.e., when the MEC of the fuel being combusted is <20.0 percent of the MPC. When the full-scale of the low range is exceeded, the high range shall be used to measure and record the NO_X concentrations; or, if applicable, the default high range value in paragraph (e) of this section shall be reported for each hour of the full-scale exceedance.

2.1.2.5 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a quarterly evaluation of the MPC, MEC, span, and range values for each NO_X monitor and shall make any necessary span and range adjustments, with corresponding monitoring plan updates, as described in paragraphs (a) through (e), below. Span and range adjustments may be required as a result of changes in the fuel supply, changes in the manner of operation of the unit, installation or removal of emission controls, etc. In implementing the provisions in paragraphs (a) through (e), below, note that NO_X data recorded during short-term, non-representative operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from the analysis; however, if the high range is exceeded, 200.0 percent of the high range must still be reported as the hourly NO_X concentration for each hour of the full-scale exceedance, in accordance with paragraph (c)(1) of this section. The owner or operator shall document all such unrepresentative operating conditions in the quarterly report required under § 75.64 and shall indicate which data have been excluded from the quarterly span and range evaluation.

Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified, except that up to 90 days after the end of that quarter may be taken to implement a span adjustment if the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value.

(a) No span or range adjustment is required if, during a calendar quarter, the hourly NO_X concentration exceeds the MPC but does not exceed the high span value. However, for missing data purposes, if any of the hourly NO_X concentrations exceed the current MPC by ≥ 5.0 percent, a new MPC equal to the highest quality assured hourly NO_X concentration recorded during the quarter must be defined in the monitoring plan. Update the monitoring plan to reflect the new MPC value.

(b) A span adjustment is required whenever any of the on-scale, quality assured, hourly NO_X concentrations exceed the high span value by ≥ 10.0 percent during a quarter but do not exceed the high range. Define a new MPC value (as applicable) equal to the highest quality assured on-scale NO_X concentration recorded during the quarter, and set the new span value according to section 2.1.2.3 or 2.1.2.4 of this appendix (as applicable), using the new MPC value. If the new span value exceeds the current full-scale range, adjust the range setting also. Update the monitoring plan to reflect the new MPC, the new span value, and (if applicable) the new full-scale range. Where separate ranges are used to measure emissions from different fuels or in different seasons (i.e. where seasonal controls are used), the low span and MEC shall be increased in the manner described in this paragraph if any on-scale hourly value exceeds the low span value by 10.0 percent or more.

(c) Whenever a full-scale range is exceeded during a quarter and the exceedance is not caused by a monitor out-of-control period, proceed as follows:

(1) For exceedances of the high range, report 200.0 percent of the current full-scale

range as the hourly NO_X concentration for each hour of the full-scale exceedance and make adjustments to the MPC, span, and range to prevent future full-scale exceedances.

(2) For units with two NO_X spans and ranges, if the low range is exceeded, no further action is required, provided that the high range is available and is not out-of-control or out-of-service for any reason. However, if the high range is not able to provide quality assured data at the time of the low range exceedance or at any time during the continuation of the exceedance, report the MPC as the NO_X concentration until the readings return to the low range or until the high range is able to provide quality assured data (unless the reason that the high-scale range is not able to provide quality assured data is because the high-scale range has been exceeded; if the high-scale range is exceeded follow the procedures in paragraph (c)(1) of this section).

(d) If the fuel supply, emission controls, or other process parameters change such that the maximum expected concentration or the maximum potential concentration changes significantly, adjust the NO_X pollutant concentration span(s) and (if necessary) monitor range(s) to assure the continued accuracy of the monitoring system. The owner or operator should evaluate whether any planned changes in operation of the unit or stack may affect the concentration of emissions being emitted from the unit and should plan any necessary span and ranges changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. Determine the adjusted span(s) using the procedures in section 2.1.2.3 or 2.1.2.4 of this appendix (as applicable). Select the full-scale range(s) of the instrument to be greater than or equal to the adjusted span value(s) and to be consistent with the guidelines of section 2.1 of this appendix.

(e) Whenever changes are made to the MPC, MEC, full-scale range, or span value of the NO_X monitor as described in paragraphs (a) through (d) of this section, record and report (as applicable) the new full-scale range setting, the new MPC or MEC, maximum potential NO_X emission rate, and the adjusted span value in an updated monitoring plan for the unit. The monitoring plan update shall be made in the quarter in which the changes become effective. In addition, record and report the adjusted span as part of the records for the daily calibration error test and linearity check required by appendix B to this part. Whenever the span value is adjusted, use calibration gas concentrations that meet the requirements of section 5.1 of this appendix, based on the adjusted span value. When a span adjustment is significant enough that the calibration gases currently being used for daily calibration error tests and linearity checks are unsuitable for use with the new span value, a linearity test using the new calibration gases must be performed and passed. Data from the monitor are considered invalid from the hour in which the span is adjusted until the required linearity check is passed in accordance with section 6.2 of this appendix.

2.1.3 CO_2 and O_2 Monitors

For an O_2 monitor (including O_2 monitors used to measure CO_2 emissions or percentage moisture), select a span value between 15.0 and 25.0 percent O_2. For a CO_2 monitor installed on a boiler, select a span value between 14.0 and 20.0 percent CO_2. For a CO_2 monitor installed on a combustion turbine, an alternative span value between 6.0 and 14.0 percent CO_2 may be used. An alternative O_2 span value below 15.0 percent O_2 may be used if an appropriate technical justification is included in the monitoring plan. Select the full-scale range of the instrument to be consistent with section 2.1 of this appendix and to be greater than or equal to the span value. Select the calibration gas concentrations for the daily calibration error tests and linearity checks in accordance with section 5.1 of this appendix, as percentages of the span value. For O_2 monitors with span values ≥21.0 percent O_2, purified instrument air containing 20.9 percent O_2 may be used as the high-level calibration material.

2.1.3.1 Maximum Potential Concentration of CO_2

For CO_2 pollutant concentration monitors, the maximum potential concentration shall be 14.0 percent CO_2 for boilers and 6.0 percent CO_2 for combustion turbines. Alternatively, the owner or operator may determine the MPC based on a minimum of 720 hours of quality assured historical CEM data representing the full operating load range of the unit(s).

2.1.3.2 Adjustment of Span and Range

Adjust the span value and range of a CO_2 or O_2 monitor according to the general guidelines in section 2.1.1.5 of this appendix (insofar as those provisions are applicable), replacing the term ''SO_2'' with ''CO_2 or O_2.'' Set the new span and range in accordance with section 2.1.3 of this appendix and provide a rationale for the new span value in the monitoring plan.

2.1.4 Flow Monitors

Select the full-scale range of the flow monitor so that it is consistent with section 2.1 of this appendix and can accurately measure all potential volumetric flow rates at the flow monitor installation site.

2.1.4.1 Maximum Potential Velocity and Flow Rate

Make an initial determination of the maximum potential velocity (MPV) using Equation A–3a or A–3b, or determine the MPV (wet basis) from velocity traverse testing using Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter. If using test values, use the highest average velocity (determined from the Method 2 traverses) measured at or near the maximum unit operating load. Express the MPV in units of wet standard feet per minute (fpm). For the purpose of providing substitute data during periods of missing flow rate data in accordance with §§ 75.31 and 75.33 and as required elsewhere in this part, calculate the maximum potential stack gas flow rate (MPF) in units of standard cubic feet per hour (scfh), as the product of the MPV (in units of wet, standard fpm) times 60, times the cross-sectional area of the stack or duct (in ft^2) at the flow monitor location.

2.1.4.2 Span Values and Range

Determine the span and range of the flow monitor as follows. Convert the MPV, as determined in section 2.1.4.1 of this appendix, to the same units of flow rate that are used for daily calibration error tests (e.g., scfh, kscfh, kacfm, or differential pressure (inches of water)). Next, determine the ''calibration span value'' by multiplying the MPV (converted to equivalent daily calibration error units) by a factor no less than 1.00 and no greater than 1.25, and rounding up the result to at least 2 significant figures. For calibration span values in inches of water, retain at least 2 decimal places. Select appropriate reference signals for the daily calibration error tests as percentages of the calibration span value. Finally, calculate the ''flow rate span value'' (in scfh) as the product of the MPF, as determined in section 2.1.4.1 of this appendix, times the same factor (between 1.00 and 1.25) that was used to calculate the calibration span value. Round off the flow rate span value to the nearest 1000 scfh. Select the full-scale range of the flow monitor so that it is greater than or equal to the span value and is consistent with section 2.1 of this appendix. Include in the monitoring plan for the unit: calculations of the MPV, MPF, calibration span value, flow rate span value, and full-scale range (expressed both in units of scfh and, if different, in the units of calibration).

$$MPV = \left(\frac{F_d H_f}{A}\right)\left(\frac{20.9}{20.9 - \%O_{2d}}\right)\left(\frac{100}{100 - \%H_2O}\right)$$

(Eq. A–3a)

or

$$MPV = \left(\frac{F_c H_f}{A}\right)\left(\frac{100}{\%CO_{2d}}\right)\left(\frac{100}{100 - \%H_2O}\right)$$

(Eq. A–3b)

Where:

MPV=maximum potential velocity (fpm, standard wet basis),

F_d=dry-basis F factor (dscf/mmBtu) from Table 1, Appendix F of this part,

F_c=carbon-based F factor (scfCO_2/mmBtu) from Table 1, Appendix F this part,

HF=maximum heat input (mmBtu/minute) for all units, combined, exhausting to the stack or duct where the flow monitor is located,

A=inside cross sectional area (ft2) of the flue at the flow monitor location,

$\%O_{2d}$=maximum oxygen concentration, percent dry basis, under normal operating conditions,

$\%CO_{2d}$=minimum carbon dioxide concentration, percent dry basis, under normal operating conditions,

$\%H_2O$=maximum percent flue gas moisture content under normal operating conditions.

2.1.4.3 Adjustment of Span and Range

For each affected unit or common stack, the owner or operator shall make a quarterly evaluation of the MPV, MPF, span, and range values for each flow rate monitor and shall make any necessary span and range adjustments with corresponding monitoring plan updates, as described in paragraphs (a) through (e), below. Span and range adjustments may be required as a result of changes in the fuel supply, changes in the stack or ductwork configuration, changes in the manner of operation of the unit, installation or removal of emission controls, etc. In implementing the provisions in paragraphs (a) through (e), below, note that flow rate data recorded during short-term, non-representative operating conditions (e.g., a trial burn of a different type of fuel) shall be excluded from the analysis; however, if the high range is exceeded, 200.0 percent of the full-scale range must still be reported as the hourly flow rate for each hour of the full-scale exceedance, in accordance with paragraph (c) of this section. The owner or operator shall document all such unrepresentative operating conditions in the quarterly report required under § 75.64 and shall indicate which data have been excluded from the quarterly span and range evaluation. Make each required span or range adjustment no later than 45 days after the end of the quarter in which the need to adjust the span or range is identified.

(a) No span or range adjustment is required if, during a calendar quarter, the hourly flow rate exceeds the MPF but does not exceed the flow rate span value. However, for missing data purposes, if any of the hourly flow rates exceed the current MPF by ≥5.0 percent, a new MPF equal to the highest quality assured hourly flow rate recorded during the quarter must be defined in the monitoring plan. Update the monitoring plan to reflect the new MPF value.

(b) A span adjustment is required whenever any of the on-scale, quality assured, hourly flow rates exceed the flow rate span value by ≥10.0 percent during a quarter. Define a new MPF equal to the highest on-scale flow rate recorded during the quarter, and set the new flow rate span value according to section 2.1.4.2 of this appendix. Then, calculate the new calibration span value by converting the new flow rate span value from units of scfh to units of daily calibration. If the new flow rate span value exceeds the current full-scale range, adjust the range setting also. Update the monitoring plan to reflect the new span and (if applicable) range values.

(c) Whenever the full-scale range is exceeded during a quarter, provided that the exceedance is not caused by a monitor out-of-control period, report 200.0 percent of the current full-scale range as the hourly flow rate for each hour of the full-scale exceedance. If the range is exceeded, make adjustments to the MPF, flow rate span, and range to prevent future full-scale exceedances. Calculate the new calibration span value by converting the new flow rate span value from units of scfh to units of daily calibration. A calibration error test must be performed and passed to validate data on the new range.

(d) If the fuel supply, stack or ductwork configuration, operating parameters, or other conditions change such that the maximum potential flow rate changes significantly, adjust the span and range to assure the continued accuracy of the flow monitor. The owner or operator should evaluate whether any planned changes in operation of the unit may affect the flow of the unit or stack and should plan any necessary span and range changes needed to account for these changes, so that they are made in as timely a manner as practicable to coordinate with the operational changes. Calculate the adjusted calibration span and flow rate span values using the procedures in section 2.1.4.2 of this appendix.

(e) Whenever changes are made to the MPV, MPF, full-scale range, or span value of the flow monitor, as described in paragraphs (a) through (d) of this section, record and report (as applicable) the new full-scale range setting, calculations of the flow rate span value, calibration span value, MPV, and MPF in an updated monitoring plan for the unit. The monitoring plan update shall be made in the quarter in which the changes become effective. Record and report the adjusted calibration span and reference values as parts of the records for the calibration error test required by appendix B to this part. Whenever the calibration span value is adjusted, use reference values for the calibration error test that meet the requirements of section 2.2.2.1 of this appendix, based on the most recent adjusted calibration span value. Perform a calibration error test according to section 2.1.1 of appendix B to this part whenever making a change to the flow monitor span or range, unless the range change also triggers a recertification under § 75.20(b).

2.1.5 Moisture Sensors

The span value of a continuous moisture sensor shall be equal to the full-scale range of the instrument. The range shall be selected in accordance with the requirements of section 2.1 of this appendix.

* * * * *

54. Section 3 of appendix A to part 75 is amended by revising section 3.1 and the last sentence in the first paragraph of section 3.2; by adding a new section 3.3.6; and by revising section 3.5, to read as follows:

3. Performance Specifications

3.1 Calibration Error

The initial calibration error of SO_2 and NO_X pollutant concentration monitors shall not deviate from the reference value of either the zero or upscale calibration gas by more than 2.5 percent of the span of the instrument, as calculated using Equation A–5 of this appendix. Alternatively, where the span value is less than 200 ppm, calibration error test results are also acceptable if the absolute value of the difference between the monitor response value and the reference value, |R–A| in Equation A–5 of this appendix, is ≥5 ppm. The calibration error of CO_2 or O_2 monitors (including O_2 monitors used to measure CO_2 emissions or percent moisture) shall not deviate from the reference value of the zero or upscale calibration gas by >0.5 percent O_2 or CO_2, as calculated using the term |R–A| in the numerator of Equation A–5 of this appendix. The calibration error of flow monitors shall not exceed 3.0 percent of the calibration span value of the instrument, as calculated using Equation A–6 of this appendix. For differential pressure-type flow monitors, the calibration error test results are also acceptable if |R—A|, the absolute value of the difference between the monitor response and the reference value in Equation A–6, does not exceed 0.01 inches of water. The calibration error of a continuous moisture sensor shall not exceed 3.0 percent of the span value, as calculated using Equation A–5 of this appendix.

3.2 Linearity Check

* * * For CO_2 or O_2 monitors (including O_2 monitors used to measure CO_2 emissions or percent moisture):

* * * * *

3.3 * * *

3.3.6 Relative Accuracy for Moisture Monitoring Systems

The relative accuracy of a moisture monitoring system shall not exceed 10.0 percent. The relative accuracy test results are also acceptable if the mean difference of the reference method measurements (in percent H_2O) and the corresponding moisture monitoring system measurements (in percent H_2O) are within ±1.0 percent H_2O.

* * * * *

3.5 Cycle Time

The cycle time for pollutant concentration monitors, oxygen monitors used to determine percent moisture, and any other continuous emission monitoring system(s) required to perform a cycle time test shall not exceed 15 minutes.

55. Section 4 of appendix A to part 75 is amended by revising the introductory paragraph and paragraph (6) to read as follows:

4. Data Acquisition and Handling Systems

Automated data acquisition and handling systems shall: (1) Read and record the full range of pollutant concentrations and volumetric flow from zero through span; and (2) provide a continuous, permanent record of all measurements and required information as an ASCII flat file capable of transmission both by direct computer-to-computer electronic transfer via modem and EPA-provided software and by an IBM-compatible personal computer diskette.

* * * * *

(6) Provide a continuous, permanent record of all measurements and required information as an ASCII flat file capable of transmission both by direct computer-to-computer electronic transfer via modem and EPA-provided software and by an IBM-compatible personal computer diskette.

56. Section 5 of appendix A to part 75 is amended by revising sections 5.1, 5.2.1, 5.2.2, 5.2.3, and 5.2.4 to read as follows:

5. Calibration Gas

5.1 Reference Gases

For the purposes of part 75, calibration gases include the following:

5.1.1 Standard Reference Materials (SRM)

These calibration gases may be obtained from the National Institute of Standards and Technology (NIST) at the following address: Quince Orchard and Cloppers Road, Gaithersburg, MD 20899–0001.

5.1.2 SRM-Equivalent Compressed Gas Primary Reference Material (PRM)

Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and Technology Laboratory of NIST, at the above address, for a list of vendors and cylinder gases.

5.1.3 NIST Traceable Reference Materials

Contact the Gas Metrology Team, Analytical Chemistry Division, Chemical Science and Technology Laboratory of NIST, at the above address, for a list of vendors and cylinder gases.

5.1.4 EPA Protocol Gases

EPA Protocol gases must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value), using the uncertainty calculation procedure in section 2.1.8 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121.

A copy of EPA–600/R–97/121 is available from the National Technical Information Service, 5285 Port Royal Road, Springfield, VA 703–487–4650 and from the Office of Research and Development, (MD–77B), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, Attn: Berne Bennett, 919–541–2366.

5.1.5 Research Gas Mixtures

Research gas mixtures must be vendor-certified to be within 2.0 percent of the concentration specified on the cylinder label (tag value), using the uncertainty calculation procedure in section 2.1.8 of the ''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, EPA–600/R–97/121. Inquiries about the RGM program should be directed to: National Institute of Standards and Technology, Analytical Chemistry Division, Chemical Science and Technology Laboratory, B–324 Chemistry, Gaithersburg, MD 20899.

5.1.6 Zero Air Material

Zero air material is defined in § 72.2 of this chapter.

5.1.7 NIST/EPA-Approved Certified Reference Materials

Existing certified reference materials (CRMs) that are still within their certification period may be used as calibration gas.

5.1.8 Gas Manufacturer's Intermediate Standards

Gas manufacturer's intermediate standards is defined in § 72.2 of this chapter.

* * * * *

5.2.1 Zero-level Concentration

0.0 to 20.0 percent of span, including span for high-scale or both low-and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

5.2.2 Low-level Concentration

20.0 to 30.0 percent of span, including span for high-scale or both low-and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

5.2.3 Mid-level Concentration

50.0 to 60.0 percent of span, including span for high-scale or both low-and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

5.2.4 High-level Concentration

80.0 to 100.0 percent of span, including span for high-scale or both low-and high-scale for SO_2, NO_X, CO_2, and O_2 monitors, as appropriate.

57. Section 6 of appendix A to part 75 is amended by revising sections 6.2, 6.3.1, 6.5, 6.5.1, 6.5.2, 6.5.6, 6.5.7, and 6.5.9 to read as follows:

6. Certification Tests and Procedures

* * * * *

6.2 Linearity Check

For the purposes of initial certification, recertification, and quality assurance, check the linearity of each SO_2, NO_X, CO_2, and O_2 monitor while the unit, or group of units for a common stack, is combusting fuel at conditions of typical stack temperature and pressure; it is not necessary for the unit to be generating electricity during this test. Notwithstanding these requirements, if the SO_2 or NO_X span value for a particular monitor range is ≤30 ppm, that range is exempted from the linearity test requirements of this part.

Challenge each monitor with calibration gas, as defined in section 5.1 of this appendix, at the low-, mid-, and high-range concentrations specified in section 5.2 of this appendix. For units using emission controls and other units using both a high and a low span, perform a linearity check on both the low-and high-scales for initial certification. For on-going quality assurance of the CEMS, perform linearity tests on the range(s) and at the frequency specified in section 2.2.1 of appendix B to this part.

Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor at its normal operating temperature and conditions. For extractive and dilution type monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in-situ type monitors, perform calibration checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the monitor three times with each reference gas (see example data sheet in Figure 1). Do not use the same gas twice in succession. The linearity check must be done hands-off, as follows. No adjustments other than the calibration adjustments described in section 2.1.3 of appendix B to this part are permitted prior to or during the linearity test period. To the extent practicable, the duration of each linearity test, from the hour of the first injection to the hour of the last injection, shall not exceed 24 unit operating hours. Record the monitor response from the data acquisition and handling system. For each concentration, use the average of the responses to determine the error in linearity using Equation A–4 in this appendix.

Linearity checks are acceptable for monitor or monitoring system certification, recertification, or quality assurance if none of the test results exceed the applicable performance specifications in section 3.2 of this appendix.

The status of emission data from a CEMS prior to and during a linearity test period shall be determined as follows:

(a) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the linearity test, have been successfully completed, unless the data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, substitute the words ''initial certification'' for ''recertification,'' and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

(b) For the routine quality assurance linearity checks required by section 2.2.1 of appendix B to this part, use the data validation procedures in section 2.2.3 of appendix B to this part.

(c) When a linearity test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

(d) For linearity tests of non-redundant backup monitoring systems, use the data validation procedures in § 75.20(d)(2)(iii).

(e) For linearity tests performed during a grace period and after the expiration of a grace period, use the data validation procedures in sections 2.2.3 and 2.2.4, respectively, of appendix B to this part.

6.3 * * *

6.3.1 Pollutant Concentration Monitor and CO_2 or O_2 Monitor 7-day Calibration Error Test

For the purposes of initial certification and recertification, measure the calibration error of each pollutant concentration monitor and CO_2 or O_2 monitor while the unit is combusting fuel at conditions of typical temperature and pressure (but not necessarily generating electricity) once each day for 7 consecutive operating days according to the following procedures. (In the event that extended unit outages occur after the commencement of the test, the 7 consecutive unit operating days need not be 7 consecutive calendar days.) Units using dual span monitors must perform the calibration error test on both high-and low-scales of the pollutant concentration monitor. The daily calibration error test procedures in this section shall also be used to perform the daily assessments and additional calibration error tests required under sections 2.1.1 and 2.1.3 of appendix B to this part.

Do not make manual or automatic adjustments to the monitor settings until after taking measurements at both zero and high concentration levels for that day during the 7-day test. If automatic adjustments are made following both injections, conduct the calibration error test such that the magnitude of the adjustments can be determined and recorded. Record and report test results for each day using the unadjusted concentration measured in the calibration error test prior to making any manual or automatic adjustments (i.e., resetting the calibration).

The calibration error tests should be approximately 24 hours apart, (unless the 7-day test is performed over non-consecutive days). Perform calibration error tests at both the zero-level concentration and either the mid-level or high-level concentration, as specified in section 5.2 of this appendix. In addition, repeat the procedure for SO_2 and NO_X pollutant concentration monitors using the low-scale for units equipped with emission controls or other units with dual span monitors. Use only calibration gas, as specified in section 5.1 of this appendix.

Introduce the calibration gas at the gas injection port, as specified in section 2.2.1 of this appendix. Operate each monitor in its normal sampling mode. For extractive and dilution type monitors, pass the calibration gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling and through as much of the sampling probe as is practical. For in-situ type monitors, perform calibration, checking all active electronic and optical components, including the transmitter, receiver, and analyzer. Challenge the pollutant concentration monitors and CO_2 or O_2 monitors once with each calibration gas. Record the monitor response from the data acquisition and handling system. Using Equation A–5 of this appendix, determine the calibration error at each concentration once each day (at approximately 24-hour intervals) for 7 consecutive days according to the procedures given in this section.

Calibration error tests are acceptable for monitor or monitoring system certification if none of these daily calibration error test results exceed the applicable performance specifications in section 3.1 of this appendix.

The status of emission data from a CEMS during a 7-day calibration error test period shall be determined as follows:

(a) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the 7-day calibration error test, have been successfully completed, unless the data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, substitute the words ''initial certification'' for ''recertification,'' and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

(b) When a 7-day calibration error test is required as a diagnostic test or for recertification, use the data validation procedures in § 75.20(b)(3).

* * * * *

6.5 Relative Accuracy and Bias Tests

For the purposes of initial certification, recertification, and quality assurance, perform the required relative accuracy test audits as follows for each CO_2 and SO_2 pollutant concentration monitor, each flow monitor, each NO_X continuous emission monitoring system, each O_2 monitor used to calculate heat input or CO_2 concentration, each moisture monitoring system, and each SO_2-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999:

(a) All relative accuracy test audits shall be done ''hands-off'', as follows:

(1) No adjustments, linearizations, or reprogramming of the CEMS, other than the calibration adjustments described in section 2.1.3 of appendix B to this part, are permitted prior to and during the RATA test period.

(2) For 2-level and 3-level flow monitor audits, no re-linearization of the monitor (i.e., changing of the polynomial coefficients) is permitted between load levels.

(b) Except as provided in § 75.21(a)(5), perform each RATA while the unit (or units, if more than one unit exhausts into the flue) is combusting the fuel that is normal for that unit (for some units, more than one type of fuel may be considered normal; e.g., a unit that combusts gas or oil on a seasonal basis). When relative accuracy test audits are performed on continuous emission monitoring systems or component(s) on bypass stacks/ducts, use the fuel normally combusted by the unit (or units, if more than one unit exhausts into the flue) when emissions exhaust through the bypass stack/ducts.

(c) Perform each RATA at the load level(s) specified in section 6.5.1 or 6.5.2 of this appendix or in section 2.3.1.3 of appendix B to this part, as applicable.

(d) For monitoring systems with dual ranges, perform the relative accuracy test on the range normally used for measuring emissions. For units with add-on SO_2 or NO_X controls or for units that need a dual range to record high concentration ''spikes'' during startup conditions, the low range is considered normal. However, for some dual span units (e.g., for units that switch fuels and have both a high and low span value), either of the two measurement ranges may be considered normal; in such cases, perform the RATA on the range that is in use at the time of the scheduled test.

(e) Record monitor or monitoring system output from the data acquisition and handling system.

(f) For initial certification and recertification RATAs and for the quality assurance RATAs required by § 75.20(d) or by section 2.3.1 of appendix B to this part, complete each single-load relative accuracy test audit within a period of 168 consecutive unit operating hours. For 2-level and 3-level flow monitor RATAs, complete all of the RATAs at all levels, to the extent practicable, within a period of 168 consecutive unit operating hours; however, if this is not possible, up to 720 consecutive unit operating hours may be taken to complete a multiple-load flow RATA.

(g) The status of emission data from the CEMS prior to and during the RATA test period shall be determined as follows:

(1) For the initial certification of a CEMS, data from the monitoring system are considered invalid until all certification tests, including the RATA, have been successfully completed, unless the data validation procedures in § 75.20(b)(3) are used. When the procedures in § 75.20(b)(3) are followed, substitute the words ''initial certification'' for ''recertification,'' and complete all of the initial certification tests by the applicable deadline in § 75.4, rather than within the time periods specified in § 75.20(b)(3)(iv) for the individual tests.

(2) For the routine quality assurance RATAs required by section 2.3.1 of appendix B to this part, use the data validation procedures in section 2.3.2 of appendix B to this part.

(3) For recertification RATAs, use the data validation procedures in § 75.20(b)(3).

(4) For quality assurance RATAs of non-redundant backup monitoring systems, use the data validation procedures in §§ 75.20(d)(2)(v) and (vi).

(5) For RATAs performed during and after the expiration of a grace period, use the data validation procedures in sections 2.3.2 and 2.3.3, respectively, of appendix B to this part.

(h) For each SO_2 or CO_2 pollutant concentration monitor, each flow monitor, and each NO_X continuous emission monitoring system, calculate the relative accuracy, in accordance with section 7.4 of this appendix. In addition (except for CO_2 monitors), test for bias and determine the appropriate bias adjustment factor, in accordance with sections 7.6.4 and 7.6.5 of this appendix, using the data from the relative accuracy test audits.

6.5.1 Gas Monitoring System RATAs (Special Considerations)

(a) For the purposes of initial certification, recertification, and quality assurance, perform the required relative accuracy test audits for each SO_2 or CO_2 pollutant

concentration monitor, each O_2 monitor, each NO_X continuous emission monitoring system, and each SO_2-diluent continuous emission monitoring system (lb/mmBtu) used by units with a qualifying Phase I technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999, at the normal load level for the unit (or combined units, if common stack), as defined in section 6.5.2.1 of this appendix. If two load levels have been designated as normal, the RATAs may be done at either load level.

(b) For the initial certification of a gas monitoring system and for recertifications in which, in addition to a RATA, one or more other tests are required (i.e., a linearity test, cycle time test, or 7-day calibration error test), EPA recommends that the RATA not be commenced until the other required tests of the CEMS have been passed.

6.5.2 Flow Monitor RATAs (Special Considerations)

(a) Except for flow monitors on bypass stacks/ducts and peaking units, perform relative accuracy test audits for the initial certification of each flow monitor at three different exhaust gas velocities (low, mid, and high), corresponding to three different load levels within the range of operation, as defined in section 6.5.2.1 of this appendix. For a common stack/duct, the three different exhaust gas velocities may be obtained from frequently used unit/load combinations for the units exhausting to the common stack. Select the three exhaust gas velocities such that the audit points at adjacent load levels (i.e., low and mid or mid and high), in megawatts (or in thousands of lb/hr of steam production), are separated by no less than 25.0 percent of the range of operation, as defined in section 6.5.2.1 of this appendix.

(b) For flow monitors on bypass stacks/ducts and peaking units, the flow monitor relative accuracy test audits for initial certification and recertification shall be single-load tests, performed at the normal load, as defined in section 6.5.2.1 of this appendix.

(c) The semiannual and annual quality assurance flow monitor RATAs required under appendix B to this part shall be done at the load level(s) specified in section 2.3.1.3 of appendix B.

(d) Flow monitor recertification RATAs shall be done at three load level(s), unless otherwise specified in paragraph (b) of this section or unless otherwise approved by the Administrator.

6.5.2.1 Range of Operation and RATA Load Levels (Definitions)

The owner or operator shall determine the upper and lower boundaries of the ''range of operation'' for each unit (or combination of units, for common-stack configurations) that uses CEMS to account for its emissions. The lower boundary of the range of operation of a unit shall be the minimum safe, stable load (or, for common-stacks, the lowest of the minimum safe, stable loads for any of the units discharging through the stack). The upper boundary of the range of operation of a unit shall be the maximum sustainable load. The ''maximum sustainable load'' is the higher of: (1) the nameplate or rated capacity of the unit, less any physical or regulatory limitations or other deratings, or (2) the highest sustainable unit load, based on at least four quarters of representative historical operating data. For common-stacks, the maximum sustainable load is the sum of all of the maximum sustainable loads of the individual units discharging through the stack, unless this load is unattainable in practice, in which case use the highest sustainable combined load for the units that discharge through the stack, based on at least four quarters of representative historical operating data. The load values for the unit(s) shall be expressed either in units of megawatts or thousands of lb/hr of steam load.

The operating levels for relative accuracy test audits shall, except for peaking units, be defined as follows: (1) the low operating level shall be the first 30.0 percent of the range of operation; (2) the mid operating level shall be the middle portion (30.0 to 60.0 percent) of the range of operation; and (3) the high operating level shall be the upper end (60.0 to 100.0 percent) of the range of operation. For example, if the upper and lower boundaries of the range of operation are 100 and 1100 megawatts, respectively, then the low, mid, and high operating levels would be 100 to 400 megawatts, 400 to 700 megawatts, and 700 to 1100 megawatts, respectively.

The provisions of this paragraph become effective January 1, 2000. This determination shall be made just prior to conducting the quality assurance RATAs required under section 2.3 of appendix B of this part (in the same calendar quarter in which the RATAs are conducted) but not required more frequently than once a year, if the RATA(s) are conducted semiannually. The owner or operator shall determine, for each unit or common stack (except for peaking units) the load level (low, mid or high) that is the most frequently used. In addition, the owner or operator shall determine which load level is the second most frequently-used. To make the determinations, the owner or operator shall construct a historical load frequency distribution (e.g., histogram), depicting the relative number of operating hours at each of the three load levels, low, mid and high. The frequency distribution shall be based upon all available data from the four most recent QA operating quarters, as defined in section 2.3.1.1 of appendix B of this part. The owner or operator shall use the frequency distribution to determine, to the nearest 0.1 percent, the percentage of the time that each load level (low, mid, high) has been used in the previous four QA operating quarters. A summary of the data used for these determinations shall be kept on-site in a format suitable for inspection and the results of the determinations shall be included in the electronic quarterly report under § 75.64.

Except for peaking units, the owner or operator shall designate the most frequently used load level as the normal load level for each unit (or combination of units, for common stacks). The owner or operator may also, if appropriate, designate the second most frequently used load level as an additional normal load level for the unit or stack. For peaking units, the entire operating load range shall be considered normal.

Beginning on January 1, 2000, the owner or operator shall report the upper and lower boundaries of the range of operation for each unit (or combination of units, for common stacks), in units of megawatts or thousands of lb/hr of steam production, in the electronic quarterly report required under § 75.64. Except for peaking units, the owner or operator shall also indicate in the electronic quarterly report: (1) the two load levels (low, mid, or high) that are the most frequently used, as determined under this section; (2) the relative (percent) historical usage of each load level, as determined under this section; and (3) the load level (or levels) designated as normal under this section.

6.5.2.2 Multi-Load Flow RATA Results

For each multi-load flow RATA, calculate the flow monitor relative accuracy at each operating level. If a flow monitor relative accuracy test is failed or aborted due to a problem with the monitor on any level of a 2-level (or 3-level) relative accuracy test audit, the RATA must be repeated at that load level. However, the entire 2-level (or 3-level) relative accuracy test audit does not have to be repeated unless the flow monitor polynomial coefficients are changed, in which case a 3-level RATA is required.

* * * * *

6.5.6 Reference Method Traverse Point Selection

Select traverse points that ensure acquisition of representative samples of pollutant and diluent concentrations, moisture content, temperature, and flue gas flow rate over the flue cross section. To achieve this, the reference method traverse points shall meet the requirements of section 3.2 of Performance Specification 2 (''PS No. 2'') in appendix B to part 60 of this chapter (for SO_2, NO_X, and moisture monitoring system RATAs), Performance Specification 3 in appendix B to part 60 of this chapter (for O_2 and CO_2 monitor RATAs), Method 1 (or 1A) (for volumetric flow rate monitor RATAs), Method 3 (for molecular weight), and Method 4 (for moisture determination) in appendix A to part 60 of this chapter.

The following alternative reference method traverse point locations are permitted for moisture and gas monitor RATAs:

(a) For all moisture determinations, a single reference method point, located at least 1.0 meter from the stack wall, may be used.

(b) For gas monitoring system RATAs, the owner or operator may use any of the following options:

(1) At any location (including locations where stratification is expected), use a minimum of six traverse points along a diameter, in the direction of any expected stratification. The points shall be located in accordance with Method 1 in appendix A to part 60 of this chapter.

(2) At locations where section 3.2 of PS No. 2 allows the use of a short reference method measurement line (with three points located at 0.4, 1.0, and 2.0 meters from the stack wall), the owner or operator may use an alternative 3-point measurement line, locating the three points at 4.4, 14.6, and 29.6 percent of the way across the stack, in

accordance with Method 1 in appendix A to part 60 of this chapter.

(3) At locations where stratification is likely to occur (i.e., following a wet scrubber or when dissimilar gas streams are combined), the short measurement line from section 3.2 of PS No. 2 (or the alternative line described in paragraph (c) of this section) may be used in lieu of the prescribed ''long'' measurement line in section 3.2 of PS No. 2, provided that the 12-point stratification test described in section 6.5.6.1 of this appendix is performed and passed one time at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix) and provided that either the 12-point stratification test or the alternative (abbreviated) stratification test in section 6.5.6.2 of this appendix is performed and passed prior to each subsequent RATA at the location (according to the acceptance criteria of section 6.5.6.3(a) of this appendix).

(4) A single reference method measurement point, located no less than 1.0 meter from the stack wall, may be used at any sampling location if the 12-point stratification test described in section 6.5.6.1 of this appendix is performed and passed one time at the location (according to the acceptance criteria of section 6.5.6.3(b) of this appendix) and provided that either the 12-point stratification test or the alternative (abbreviated) stratification test in section 6.5.6.2 of this appendix is performed and passed prior to each subsequent RATA at the location (according to the acceptance criteria of section 6.5.6.3(b) of this appendix).

6.5.6.1 Stratification Test

(a) With the unit(s) operating under steady-state conditions at normal load, as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO_2 or NO_X) and diluent (CO_2 or O_2) concentrations at a minimum of twelve (12) points, located according to Method 1 in appendix A to part 60 of this chapter.

(b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.

(c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 2-hour period.

(d) If the load has remained constant (± 3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.

(e) Calculate the average NO_X, SO_2, and CO_2 (or O_2) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_X, SO_2, and CO_2 (or O_2) concentrations for all traverse points.

6.5.6.2 Alternative (Abbreviated) Stratification Test

(a) With the unit(s) operating under steady-state conditions at normal load, as defined in section 6.5.2.1 of this appendix, use a traversing gas sampling probe to measure the pollutant (SO_2 or NO_X) and diluent (CO_2 or O2) concentrations at three points. The points shall be located according to the specifications for the long measurement line in section 3.2 of PS No. 2 (i.e., locate the points 16.7 percent, 50.0 percent, and 83.3 percent of the way across the stack). Alternatively, the concentration measurements may be made at six traverse points along a diameter. The six points shall be located in accordance with Method 1 in appendix A to part 60 of this chapter.

(b) Use Methods 6C, 7E, and 3A in appendix A to part 60 of this chapter to make the measurements. Data from the reference method analyzers must be quality assured by performing analyzer calibration error and system bias checks before the series of measurements and by conducting system bias and calibration drift checks after the measurements, in accordance with the procedures of Methods 6C, 7E, and 3A.

(c) Measure for a minimum of 2 minutes at each traverse point. To the extent practicable, complete the traverse within a 1-hour period.

(d) If the load has remained constant (± 3.0 percent) during the traverse and if the reference method analyzers have passed all of the required quality assurance checks, proceed with the data analysis.

(e) Calculate the average NO_X, SO_2, and CO_2 (or O_2) concentrations at each of the individual traverse points. Then, calculate the arithmetic average NO_X, SO_2, and CO_2 (or O_2) concentrations for all traverse points.

6.5.6.3 Stratification Test Results and Acceptance Criteria

(a) For each pollutant or diluent gas, the short reference method measurement line described in section 3.2 of PS No. 2 may be used in lieu of the long measurement line prescribed in section 3.2 of PS No. 2, if the results of a stratification test, conducted in accordance with section 6.5.6.1 or 6.5.6.2 of this appendix (as appropriate; see section 6.5.6(b)(3) of this appendix), show that the concentration at each individual traverse point differs by no more than ±10.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ±5 ppm or ±0.5 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points.

(b) For each pollutant or diluent gas, a single reference method measurement point, located at least 1.0 meter from the stack wall may be used for that pollutant or diluent gas if the results of a stratification test, conducted in accordance with section 6.5.6.1 or 6.5.6.2 of this appendix (as appropriate; see section 6.5.6(b)(4) of this appendix), show that the concentration at each individual traverse point differs by no more than ±5.0 percent from the arithmetic average concentration for all traverse points. The results are also acceptable if the concentration at each individual traverse point differs by no more than ±3 ppm or ±0.3 percent CO_2 (or O_2) from the arithmetic average concentration for all traverse points.

(c) The owner or operator shall keep the results of all stratification tests on-site, suitable for inspection, as part of the supplementary RATA records required under § 75.56(a)(7) or § 75.59(a)(7), as applicable.

6.5.7 Sampling Strategy

Conduct the reference method tests so they will yield results representative of the pollutant concentration, emission rate, moisture, temperature, and flue gas flow rate from the unit and can be correlated with the pollutant concentration monitor, CO_2 or O_2 monitor, flow monitor, and SO_2 or NO_X continuous emission monitoring system measurements. The minimum acceptable time for a gas monitoring system RATA run or for a moisture monitoring system RATA run is 21 minutes. For each run of a gas monitoring system RATA, all necessary pollutant concentration measurements, diluent concentration measurements, and moisture measurements (if applicable) must, to the extent practicable, be made within a 60-minute period. For NO_X-diluent or SO_2-diluent monitoring system RATAs, the pollutant and diluent concentration measurements must be made simultaneously. For flow monitor RATAs, the minimum time per run shall be 5 minutes. Flow rate reference method measurements may be made either sequentially from port to port or simultaneously at two or more sample ports. The velocity measurement probe may be moved from traverse point to traverse point either manually or automatically. If, during a flow RATA, significant pulsations in the reference method readings are observed, be sure to allow enough measurement time at each traverse point to obtain an accurate average reading (e.g., a ''sight-weighted'' average from a manometer). A minimum of one set of auxiliary measurements for stack gas molecular weight determination (i.e., diluent gas data and moisture data) is required for every clock hour of a flow RATA or for every three test runs (whichever is less restrictive). Successive flow RATA runs may be performed without waiting in-between runs. If an O_2-diluent monitor is used as a CO_2 continuous emission monitoring system, perform a CO_2 system RATA (i.e., measure CO_2, rather than O_2, with the reference method). To properly correlate individual SO_2 or NO_X continuous emission monitoring system data (in lb/mmBtu) and volumetric flow rate data with the reference method data, annotate the beginning and end of each reference method test run (including the exact time of day) on the individual chart recorder(s) or other permanent recording device(s).

* * * * *

6.5.9 Number of Reference Method Tests

Perform a minimum of nine sets of paired monitor (or monitoring system) and reference method test data for every required (i.e., certification, recertification, semiannual, or annual) relative accuracy test audit. For 2-level and 3-level relative accuracy test audits of flow monitors, perform a minimum of nine sets at each of the operating levels.

Note: The tester may choose to perform more than nine sets of reference method tests. If this option is chosen, the tester may reject a maximum of three sets of the test results, as long as the total number of test

results used to determine the relative accuracy or bias is greater than or equal to nine. Report all data, including the rejected CEM data and corresponding reference method test results.

* * * * *

58. Section 7 of appendix A to part 75 is amended by revising the introductory text of section 7.2.1 and the term ''R'' following equation A–5 and by revising section 7.6.4; and by adding 4 paragraphs at the end of section 7.6.5 and a new section 7.7 to read as follows:

7. Calculations

* * * * *

7.2 * * *

7.2.1 Pollutant Concentration and Diluent Monitors

For each reference value, calculate the percentage calibration error based upon instrument span for daily calibration error tests using the following equation:

* * * * *

(Eq. A–5)

Where:

R=Reference value of zero or upscale (high-level or mid-level, as applicable) calibration gas introduced into the monitoring system.

* * * * *

7.6.4 Bias Test

For gas monitoring systems, if the mean difference, d, is greater than the absolute value of the confidence coefficient, |cc|, the monitor or monitoring system has failed to meet the bias test requirement. For flow monitor bias tests, if the mean difference, d, is greater than |cc| at any load level designated as normal under section 6.5.2.1 of this appendix, the monitor has failed to meet the bias test requirement.

7.6.5 * * *

For single-load RATAs of SO_2-and NO_X-diluent monitoring systems and for single-load flow RATAs required or allowed under section 6.5.2 of this appendix and sections 2.3.1.3(b) and 2.3.1.3(c) of appendix B to this part, the appropriate BAF is determined directly from the RATA results at normal load, using Equation A–12. Notwithstanding, when a NO_X or SO_2 CEMS installed on a low-emitting affected unit (i.e., average SO_2 concentration during the RATA <250 ppm or average NO_X emission rate <0.200 lb/mmBtu) meets the normal 10.0 percent relative accuracy specification (as calculated using Equation A–10) or the alternate relative accuracy specification in section 3.3 of this appendix for low-emitters, but fails the bias test, the BAF may be determined using Equation A–12, or a default BAF of 1.111 may be used.

For a 2-level flow RATA, if the RATA is passed but the bias test is failed at a load level designated as normal under section 6.5.2.1 of this appendix, use Equation A–12 to calculate the bias adjustment factor at both of the operating levels. For a 3-level flow monitor relative accuracy test audit, if the RATA is passed but the bias test is failed at a load level designated as normal under section 6.5.2.1 of this appendix, calculate bias adjustment factors only for the two most-frequently used load levels, as determined in section 6.5.2.1 of this appendix. For both 2-level and 3-level flow RATAs, whenever the bias test is failed at a load level designated as normal under section 6.5.2.1 of this appendix, apply the larger of the two calculated bias adjustment factors to subsequent flow monitor data using Equation A–11.

Each time a RATA is successfully completed and the appropriate bias adjustment factor has been determined, apply the BAF prospectively to all monitoring system data, beginning with the first clock hour following the hour in which the RATA was completed. For a 2-load flow RATA, the ''hour in which the RATA was completed'' refers to the hour in which the testing at both loads was completed; for a 3-load RATA, it refers to the hour in which the testing at all three loads was completed.

Use the bias-adjusted values in computing substitution values in the missing data procedure, as specified in subpart D of this part, and in reporting the concentration of SO_2, the flow rate, and the average NO_X emission rate, the unit heat input, and the calculated mass emissions of SO_2 and CO_2 during the quarter and calendar year, as specified in subpart G of this part.

7.7 Reference Flow-to-Load Ratio or Gross Heat Rate

The owner or operator shall determine R_{ref}, the reference value of the ratio of flow rate to unit load, each time that a successful flow RATA is performed at a load level designated as normal in section 6.5.2.1 of this appendix. The owner or operator shall report the current value of R_{ref} in the electronic quarterly report required under § 75.64 and shall also report the completion date of the associated RATA. If two load levels have been designated as normal under section 6.5.2.1 of this appendix, the owner or operator shall determine a separate R_{ref} value for each of the normal load levels. The requirements of this section shall become effective as of January 1, 2000. The reference flow-to-load ratio shall be calculated as follows:

$$R_{ref} = \frac{Q_{ref}}{L_{avg}} \times 10^{-5}$$

(Eq. A–13)

Where:

R_{ref}=Reference value of the flow-to-load ratio, from the most recent normal-load flow RATA, scfh/megawatts or scfh/1000 lb/hr of steam.

Q_{ref}=Average stack gas volumetric flow rate measured by the reference method during the normal-load RATA, scfh.

L_{avg}=Average unit load during the normal-load flow RATA, megawatts or 1000 lb/hr of steam.

In Equation A–13, for a common stack, L_{avg} shall be the sum of the operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks, Q_{ref} will be the sum of the total volumetric flow rates that discharge through all of the stacks. Round off the value of R_{ref} to 2 decimal places.

In addition to determining R_{ref} or as an alternative to determining R_{ref}, a reference value of the gross heat rate (GHR) may be determined. In order to use this option, quality assured diluent gas (CO_2 or O_2) must be available for each hour of the most recent normal-load flow RATA. The reference value of the GHR shall be determined as follows:

$$(GHR)_{ref} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000$$

(Eq. A–13a)

Where:

$(GHR)_{ref}$=Reference value of the gross heat rate at the time of the most recent normal-load flow RATA, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_{avg}$=Average hourly heat input during the normal-load flow RATA, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

L_{avg}=Average unit load during the normal-load flow RATA, megawatts or 1000 lb/hr of steam.

In the calculation of $(\text{Heat Input})_{avg}$, use Q_{ref}, the average volumetric flow rate measured by the reference method during the RATA, and use the average diluent gas concentration measured during the flow RATA.

* * * * *

59. Section 1 of appendix B to part 75 is revised as follows:

Appendix B to Part 75—Quality Assurance and Quality Control Procedures

1. Quality Assurance/Quality Control Program

Develop and implement a quality assurance/quality control (QA/QC) program for the continuous emission monitoring systems, excepted monitoring systems approved under appendix D, E, or I to this part, and alternative monitoring systems under subpart E of this part, and their components. At a minimum, include in each QA/QC program a written plan that describes in detail (or that refers to separate documents containing) complete, step-by-step procedures and operations for each of the following activities. Upon request from regulatory authorities, the source shall make all procedures, maintenance records, and ancillary supporting documentation from the manufacturer (e.g., software coefficients and troubleshooting diagrams) available for review during an audit.

1.1 Requirements for All Monitoring Systems

1.1.1 Preventive Maintenance

Keep a written record of procedures needed to maintain the monitoring system in proper operating condition and a schedule for those procedures. This shall, at a minimum, include procedures specified by the manufacturers of the equipment and, if applicable, additional or alternate procedures developed for the equipment.

1.1.2 Recordkeeping and Reporting

Keep a written record describing procedures that will be used to implement the recordkeeping and reporting requirements in subparts E, F, and G and appendices D, E, and I of this part, as applicable.

1.1.3 Maintenance Records

Keep a record of all testing, maintenance, or repair activities performed on any monitoring system or component in a location and format suitable for inspection. A maintenance log may be used for this purpose. The following records should be maintained: date, time, and description of any testing, adjustment, repair, replacement, or preventive maintenance action performed on any monitoring system and records of any corrective actions associated with a monitor's outage period. Additionally, any adjustment that recharacterizes a system's ability to record and report emissions data must be recorded (e.g., changing flow monitor polynomial coefficients, temperature and pressure coefficients, and dilution ratio settings), and a written explanation of the procedures used to make the adjustment(s) shall be kept.

1.2 Specific Requirements for Continuous Emissions Monitoring Systems

1.2.1 Calibration Error Test and Linearity Check Procedures

Keep a written record of the procedures used for daily calibration error tests and linearity checks (e.g., how gases are to be injected, adjustments of flow rates and pressure, introduction of reference values, length of time for injection of calibration gases, steps for obtaining calibration error or error in linearity, determination of interferences, and when calibration adjustments should be made). Identify any calibration error test and linearity check procedures specific to the continuous emission monitoring system that vary from the procedures in appendix A to this part.

1.2.2 Calibration and Linearity Adjustments

Explain how each component of the continuous emission monitoring system will be adjusted to provide correct responses to calibration gases, reference values, and/or indications of interference both initially and after repairs or corrective action. Identify equations, conversion factors, assumed moisture content, and other factors affecting calibration of each continuous emission monitoring system.

1.2.3 Relative Accuracy Test Audit Procedures

Keep a written record of procedures and details peculiar to the installed continuous emission monitoring systems that are to be used for relative accuracy test audits, such as sampling and analysis methods.

1.2.4 Parametric Monitoring for Units with Add-on Emission Controls

The owner or operator shall keep a written (or electronic) record including a list of operating parameters for the add-on SO_2 or NO_X emission controls, including parameters in § 75.55(b) or § 75.58(b), as applicable, and the range of each operating parameter that indicates the add-on emission controls are operating properly. The owner or operator shall keep a written (or electronic) record of the parametric monitoring data during each SO_2 or NO_X missing data period.

1.3 Specific Requirements for Excepted Systems Approved under Appendices D, E, and I

1.3.1 Fuel Flowmeter Accuracy Test Procedures

Keep a written record of the specific fuel flowmeter accuracy test procedures. These may include: standard methods or specifications listed in § 75.20(g) and section 2.1.5.1 of appendix D to this part and incorporated by reference under § 75.6; the procedures of sections 2.1.5.2 or 2.1.7 of appendix D to this part; or other methods approved by the Administrator through the petition process of § 75.66(c).

1.3.2 Transducer or Transmitter Accuracy Test Procedures

Keep a written record of the procedures for testing the accuracy of transducers or transmitters of an orifice-, nozzle-, or venturi-type fuel flowmeter under section 2.1.6 of appendix D to this part. These procedures should include a description of equipment used, steps in testing, and frequency of testing.

1.3.3 Fuel Flowmeter, Transducer, or Transmitter Calibration and Maintenance Records

Keep a record of adjustments, maintenance, or repairs performed on the fuel flowmeter monitoring system. Keep records of the data and results for fuel flowmeter accuracy tests and transducer accuracy tests, consistent with appendix D to this part.

1.3.4 Primary Element Inspection Procedures

Keep a written record of the standard operating procedures for inspection of the primary element (i.e., orifice, venturi, or nozzle) of an orifice-, venturi-, or nozzle-type fuel flowmeter. Examples of the types of information to be included are: what to examine on the primary element; how to identify if there is corrosion sufficient to affect the accuracy of the primary element; and what inspection tools (e.g., boroscope), if any, are used.

1.3.5 Fuel Sampling Method and Sample Retention

Keep a written record of the standard procedures used to perform fuel sampling, either by utility personnel or by fuel supply company personnel. These procedures should specify the portion of the ASTM method used, as incorporated by reference under § 75.6, or other methods approved by the Administrator through the petition process of § 75.66(c). These procedures should describe safeguards for ensuring the availability of an oil sample (e.g., procedure and location for splitting samples, procedure for maintain sample splits on site, and procedure for transmitting samples to an analytical laboratory). These procedures should identify the ASTM analytical methods used to analyze sulfur content, gross calorific value, and density, as incorporated by reference under § 75.6, or other methods approved by the Administrator through the petition process of § 75.66(c).

1.3.6 Appendix E Monitoring System Quality Assurance Information

Identify the unit manufacturer's recommended range of quality assurance- and quality control-related operating parameters. Keep records of these operating parameters for each hour of unit operation (i.e., fuel combustion). Keep a written record of the procedures used to perform NO_X emission rate testing. Keep a copy of all data and results from the initial and from the most recent NO_X emission rate testing, including the values of quality assurance parameters specified in section 2.3 of appendix E to this part.

1.3.7 Appendix I Additional Requirements

1.3.7.1 For all appendix I systems, the fuel sampling and analysis requirements in section 1.3.5 of this appendix shall be met; and, for the diluent monitor, the Calibration Error Test and Linearity Check Procedures requirements in sections 1.2.1 and 1.2.2 of this appendix shall be met.

1.3.7.2 For appendix I systems that are certified according to the system certification procedures, the Relative Accuracy Test Audit Procedures requirement in section 1.2.3 of this appendix shall be met for the annual or semiannual Method 2 flow RATA.

1.3.7.3 For appendix I systems that are certified according to the component-by-component certification procedures, the fuel flowmeter requirements applicable to the type of fuel flowmeter used in sections 1.3.1 through 1.3.5 of this appendix shall be met. The Relative Accuracy Test Audit Procedures requirement in section 1.2.3 of this appendix shall be met for the diluent monitor that is part of the appendix I system.

1.4 Requirements for Alternative Systems Approved under Subpart E

1.4.1 Daily Quality Assurance Tests

Explain how the daily assessment procedures specific to the alternative monitoring system are to be performed.

1.4.2 Daily Quality Assurance Test Adjustments

Explain how each component of the alternative monitoring system will be adjusted in response to the results of the daily assessments.

1.4.3 Relative Accuracy Test Audit Procedures

Keep a written record of procedures and details peculiar to the installed alternative monitoring system that are to be used for relative accuracy test audits, such as sampling and analysis methods.

60. Section 2 of appendix B to part 75 is amended by:

a. Revising sections 2.1.1, 2.1.3, 2.1.4, 2.2, 2.3; revising paragraph (1) of section 2.1.5.1;

b. Redesignating existing section 2.4 as section 2.5; and

c. Adding a new section 2.4, to read as follows:

2. Frequency of Testing

* * * * *

2.1 * * *

2.1.1 Calibration Error Test

Except as provided in section 2.1.1.2 of this appendix, perform the daily calibration error test of each gas monitoring system (including moisture monitoring systems consisting of wet- and dry-basis O_2 analyzers) according to the procedures in section 6.3.1 of appendix A to this part, and perform the daily calibration error test of each flow monitoring system according to the procedure in section 6.3.2 of appendix A to this part. For continuous moisture sensors, follow the manufacturer's recommended procedures for the daily calibration error check. Include the calibration procedures as part of the quality assurance program required under section 1 of this appendix.

* * * * *

2.1.3 Additional Calibration Error Tests and Calibration Adjustments

In addition to the daily calibration error tests required under section 2.1.1 of this appendix, a calibration error test of a CEMS shall be performed in accordance with section 2.1.1 of this appendix, as follows: (1) whenever a daily calibration error test is failed; (2) whenever a monitoring system is returned to service following repair or corrective maintenance that could affect the monitor's ability to accurately measure and record emissions data; and (3) after making certain calibration adjustments, as described in this section. In all cases, data from the CEMS are considered invalid until the required additional calibration error test has been successfully completed.

Routine calibration adjustments of a monitor are permitted after any successful calibration error test. These routine adjustments shall be made so as to bring the monitor readings as close as practicable to the known tag values of the calibration gases or to the actual value of the flow monitor reference signals. An additional calibration error test is required following routine calibration adjustments where the monitor's calibration has been physically adjusted (e.g., by turning a potentiometer) to verify that the adjustments have been made properly. An additional calibration error test is not required, however, if the routine calibration adjustments are made by means of a mathematical algorithm programmed into the data acquisition and handling system. The EPA recommends that routine calibration adjustments be made, at a minimum, whenever the daily calibration error exceeds the limits of the applicable performance specification in appendix A to this part for the pollutant concentration monitor, CO_2 or O_2 monitor, or flow monitor.

Additional (non-routine) calibration adjustments of a monitor are permitted, provided that an appropriate technical justification is included in the quality control program required under section 1 of this appendix. The allowable non-routine adjustments are as follows. The owner or operator may physically adjust the calibration of a monitor (e.g., by means of a potentiometer), provided that the post-adjustment zero and upscale responses of the monitor are within the performance specifications of the instrument given in section 3.1 of appendix A to this part. An additional calibration error test is required following such adjustments to verify that the monitor is operating within the performance specifications.

2.1.4 Data Validation

(a) An out-of-control period occurs when the calibration error of an SO_2 or NO_X pollutant concentration monitor exceeds 5.0 percent of the span value (or exceeds 10 ppm, for span values <200 ppm), when the calibration error of a CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or percent moisture) exceeds 1.0 percent O_2 or CO_2, or when the calibration error of a flow monitor or a moisture sensor exceeds 6.0 percent of the span value, which is twice the applicable specification of appendix A to this part. Notwithstanding, a differential pressure-type flow monitor for which the calibration error exceeds 6.0 percent of the span value shall not be considered out-of-control if $|R - A|$, the absolute value of the difference between the monitor response and the reference value in Equation A–6, is ≤0.02 inches of water. The out-of-control period begins with the hour of completion of the failed calibration error test and ends with the hour following the hour of completion of a successful calibration error test. Note, however, that if the failed calibration, corrective action, and successful calibration error test occur within the same hour, emission data for that hour recorded by the monitor after the successful calibration error test may be used for reporting purposes, provided that 2 or more valid readings are obtained as required by § 75.10. A NO_X-diluent continuous emission monitoring system is considered out-of-control if the calibration error of either component monitor exceeds twice the applicable performance specification in appendix A to this part. Emission data shall not be reported from an out-of-control monitor.

(b) An out-of-control period also occurs whenever interference of a flow monitor is identified. The out-of-control period begins with the hour of completion of the failed interference check and ends with the hour of completion of an interference check that is passed.

2.1.5 * * *

2.1.5.1 * * *

(1) Data from a monitoring system are invalid, beginning with the first hour following the expiration of a 26-hour data validation period or beginning with the first hour following the expiration of an 8-hour start-up grace period (as provided under section 2.1.5.2 of this appendix), if the required subsequent daily assessment has not been conducted.

* * * * *

2.2 Quarterly Assessments

For each primary and redundant backup continuous emission monitoring system, perform the following quarterly assessments. This requirement is effective as of the calendar quarter following the calendar quarter in which the monitor or continuous emission monitoring system is provisionally certified.

2.2.1 Linearity Check

Perform a linearity check, in accordance with the procedures in section 6.2 of appendix A to this part, for each primary and redundant backup SO_2 and NO_X pollutant concentration monitor and each primary and redundant backup CO_2 or O_2 monitor (including O_2 monitors used to measure CO_2 emissions or to continuously monitor moisture) at least once during each QA operating quarter. A QA operating quarter is a calendar quarter in which the unit operates (i.e., combusts fuel) for at least 168 hours or, for common stacks and bypass stacks, a calendar quarter in which flue gases are discharged through the stack for at least 168 hours. For units using both a low and high span value, a linearity check is required only on the range(s) used to record and report emission data during the QA operating quarter. Conduct the linearity checks no less than 30 days apart, to the extent practicable. The data validation procedures in section 2.2.3 of this appendix shall be followed.

2.2.2 Leak Check

For differential pressure flow monitors, perform a leak check of all sample lines (a manual check is acceptable) at least once during each QA operating quarter. For this test, the unit does not have to be in operation. Conduct the leak checks no less than 30 days apart, to the extent practicable. If a leak check is failed, follow the applicable data validation procedures in section 2.2.3(f) of this appendix.

2.2.3 Data Validation

(a) A routine quality assurance linearity test shall not be commenced if the monitoring system is operating out-of-control with respect to any of the daily, quarterly, or semiannual quality assurance assessments required by sections 2.1, 2.2, and 2.3 of this appendix or with respect to the additional calibration error test requirements in section 2.1.3 of this appendix.

(b) Linearity checks shall be done hands-off, as follows. No adjustments of the monitor are permitted prior to or during the linearity test period, other than the routine and non-routine calibration adjustments described in section 2.1.3 of this appendix. The non-routine adjustments are permitted only prior to the test, not during the test period.

(c) If a daily calibration error test is failed during a linearity test period, prior to completing the test, the linearity test is invalidated and must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful calibration error test. The linearity test shall not be re-commenced until the monitor has successfully completed a calibration error test.

(d) An out-of-control period occurs when a linearity test is failed (i.e., when the error in linearity at any of the three concentrations in the quarterly linearity check (or any of the six concentrations, when both ranges of a single analyzer with a dual range are tested) exceeds the applicable specification in

section 3.2 of appendix A to this part) or when a linearity test is aborted due to a problem with the CEMS. For a NO_X-diluent or SO_2-diluent continuous emission monitoring system, the system is considered out-of-control if either of the component monitors exceeds the applicable specification in section 3.2 of appendix A to this part or if the linearity test of either component is aborted due to a problem with the monitor. The out-of-control period begins with the hour of the failed or aborted linearity check and ends with the hour of completion of a satisfactory linearity check following corrective action and/or monitor repair. Note that a monitor shall not be considered out-of-control when a linearity test is aborted for a reason unrelated to the monitor's performance (e.g., a forced unit outage).

(e) No more than four successive calendar quarters shall elapse after the quarter in which a linearity check of a CEMS (or range of a CEMS) was last performed without a subsequent linearity test having been conducted. If a linearity test has not been completed by the end of the fourth calendar quarter since the last linearity test, then the linearity test must be completed within a 168 unit operating hour ''grace period'' (as provided in section 2.2.4 of this appendix) following the end of the fourth successive elapsed calendar quarter, or data from the CEMS (or range) will become invalid.

(f) An out-of-control period also occurs when a flow monitor sample line leak is detected. The out-of-control period begins with the hour of the failed leak check and ends with the hour of a satisfactory leak check following corrective action.

(g) For each monitoring system, report the results of all completed and partial linearity tests that affect data validation (i.e., all completed, passed linearity checks; all completed, failed linearity checks; and all linearity checks aborted due to a problem with the monitor) in the quarterly report required under § 75.64. Note that linearity attempts which are aborted or invalidated due to problems with the reference calibration gases or due to operational problems with the affected unit(s) need not be reported. Such partial tests do not affect the validation status of emission data recorded by the monitor. However, a record of all linearity tests and attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.

2.2.4 Linearity and Leak Check Grace Period

When a required linearity test or flow monitor leak check has not been completed by the end of the QA operating quarter in which it is due or if, due to infrequent operation of a unit or infrequent use of a required high range of a CEMS, four successive calendar quarters have elapsed after the quarter in which a linearity check of a CEMS (or range) was last performed without a subsequent linearity test having been done, the owner or operator has a grace period of 168 consecutive unit operating hours in which to perform a linearity test or leak check of that CEMS (or range). The grace period begins with the first unit operating hour following the calendar quarter in which the linearity test was due. Data validation during a linearity or leak check grace period shall be done in accordance with the applicable provisions in section 2.2.3 of this appendix.

If, at the end of the 168 unit operating hour grace period, the required linearity test or leak check has not been completed, data from the monitoring system (or range) shall be invalid, beginning with the hour following the expiration of the grace period. Data from the monitoring system (or range) remain invalid until the hour of completion of a subsequent successful hands-off linearity test or leak check of the CEMS (or range). Note that when a linearity test or a leak check is conducted within a grace period for the purpose of satisfying the linearity test or leak check requirement from a previous QA operating quarter, the results of that linearity test or leak check may only be used to meet the linearity check or leak check requirement of the previous quarter, not the quarter in which the grace period is used.

2.2.5 Flow-to-Load Ratio or Gross Heat Rate Evaluation

For each installed flow rate monitoring system on each unit or common stack, the owner or operator shall evaluate the flow-to-load ratio quarterly, i.e., for each QA operating quarter, as defined in sections 2.2.1 and 2.3.1.1 of this appendix. At the end of each QA operating quarter, the owner or operator shall use Equation B–1 in this appendix to calculate the flow-to-load ratio for every hour during the quarter in which: (1) the unit (or combination of units, for a common stack) operated within ±10.0 percent of L_{avg}, the average load during the most recent normal-load flow RATA; and (2) a quality assured hourly average flow rate was obtained with a certified flow rate monitor.

$$R_h = \frac{Q_h}{L_h} \times 1000$$

(Eq. B–1)

Where:

R_h = Hourly value of the flow-to-load ratio, scfh/megawatts *or* scfh/1000 lb/hr of steam load.

Q_h = Hourly stack gas volumetric flow rate, as measured by the flow rate monitor, scfh.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam; must be within ±10.0 percent of L_{avg} during the most recent normal-load flow RATA.

In Equation B–1, the owner or operator may use either bias-adjusted flow rates or unadjusted flow rates, provided that all of the ratios are calculated the same way. For a common stack, L_h shall be the sum of the hourly operating loads of all units that discharge through the stack. For a unit that discharges its emissions through multiple stacks or monitors its emissions in multiple breechings, Qh will be the combined hourly volumetric flow rate for all of the stacks or ducts. Round off each value of R_h to 2 decimal places.

Alternatively, the owner or operator may calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. The hourly GHR shall be determined only for those hours in which quality assured flow rate data and diluent gas (CO_2 or O_2) concentration data are both available from a certified CEMS or reference method. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000$$

(Eq. B–1a)

Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_h$ = Hourly heat input, as determined from the quality assured flow rate and diluent data, using the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam; must be within ± 10.0 percent of L_{avg} during the most recent normal-load flow RATA.

In Equation B–1a, the owner or operator may either use bias-adjusted flow rates or unadjusted flow rates in the calculation of (Heat Input)h, provided that all of the heat input values are determined in the same manner.

The owner or operator shall evaluate the calculated hourly flow-to-load ratios (or gross heat rates) as follows. A separate data analysis shall be performed for each primary and each redundant backup flow rate monitor used to record and report data during the quarter. Each analysis shall be based on a minimum of 168 hours of data. When two RATA load levels are designated as normal, the analysis shall be performed at the higher load level, unless there are fewer than 168 data points available at that load level, in which case the analysis shall be performed at the lower load level. If, for a particular flow monitor, fewer than 168 hourly flow-to-load ratios (or GHR values) are available at any of the load levels designated as normal, a flow-to-load (or GHR) evaluation is not required for that monitor for that calendar quarter.

For each flow monitor, use Equation B–2 in this appendix to calculate E_h, the absolute percentage difference between each hourly R_h value and R_{ref}, the reference value of the flow-to-load ratio, as determined in accordance with section 7.7 of appendix A to this part. Note that R_{ref} shall always be based upon the most recent normal-load RATA, even if that RATA was performed in the calendar quarter being evaluated.

$$E_h = \frac{|R_{ref} - R_h|}{R_{ref}} \times 100$$

(Eq. B–2)

Where:

E_h = Absolute percentage difference between the hourly average flow-to-load ratio and the reference value of the flow-to-load ratio at normal load.

R_h = The hourly average flow-to-load ratio, for each flow rate recorded at a load level within ± 10.0 percent of L_{avg}.

R_{ref} = The reference value of the flow-to-load ratio from the most recent normal-load flow RATA, determined in accordance with section 7.7 of appendix A to this part.

Equation B–2 shall be used in a consistent manner. That is, use R_{ref} and R_h if the flow-to-load ratio is being evaluated, and use $(GHR)_{ref}$ and $(GHR)_h$ if the gross heat rate is being evaluated. Finally, calculate E_f, the arithmetic average of all of the hourly E_h values. The owner or operator shall report the results of each quarterly flow-to-load (or gross heat rate) evaluation, as determined from Equation B–2, in the electronic quarterly report required under § 75.64.

The results of a quarterly flow-to-load (or gross heat rate) evaluation are acceptable, and no further action is required, if the calculated value of E_f is less than or equal to: (i) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥50 megawatts (or ≥500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; (ii) 10.0 percent, if L_{avg} for the most recent normal-load flow RATA is ≥50 megawatts (or ≥500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations; (iii) 20.0 percent, if L_{avg} for the most recent normal-load flow RATA is <50 megawatts (or <500 klb/hr of steam) and if unadjusted flow rates were used in the calculations; or (iv) 15.0 percent, if L_{avg} for the most recent normal-load flow RATA is <50 megawatts (or <500 klb/hr of steam) and if bias-adjusted flow rates were used in the calculations.

If E_f is above these limits, the owner or operator shall: (a) implement Option 1 in section 2.2.5.1 of this appendix; (b) perform a RATA in accordance with Option 2 in section 2.2.5.2 of this appendix; or (c) re-examine the hourly data used for the flow-to-load or GHR analysis and recalculate E_f, after excluding all non-representative hourly flow rates.

If the owner or operator chooses to recalculate E_f, the flow rates for the following hours are considered non-representative and may be excluded from the data analysis:

(1) Any hour in which the type of fuel combusted was different from the fuel burned during the most recent normal-load RATA. For purposes of this determination, the type of fuel is different if the fuel is in a different state of matter (i.e., solid, liquid, or gas) than is the fuel burned during the RATA or if the fuel is a different classification of coal (e.g., bituminous versus sub-bituminous);

(2) Any hour in which an SO_2 scrubber was bypassed;

(3) Any hour in which ''ramping'' occurred, i.e., the hourly load differed by more than ±15.0 percent from the load during the preceding hour or the subsequent hour;

(4) If a normal-load flow RATA was performed and passed during the quarter being analyzed, any hour prior to completion of that RATA; and

(5) If a problem with the accuracy of the flow monitor was discovered during the quarter and was corrected (as evidenced by passing the abbreviated flow-to-load test in section 2.2.5.3 of this appendix), any hour prior to completion of the abbreviated flow-to-load test.

After identifying and excluding all non-representative hourly data in accordance with (1) through (5) above, the owner or operator may analyze the remaining data a second time. At least 168 representative hourly ratios or GHR values must be available to perform the analysis; otherwise, the flow-to-load (or GHR) analysis is not required for that monitor for that calendar quarter.

If, after re-analyzing the data, E_f meets the applicable limit in (i),(ii), (iii), or (iv), above, no further action is required. If, however, E_f is still above the applicable limit, the monitor shall be declared out-of-control, beginning with the first hour of the quarter following the quarter in which E_f exceeded the applicable limit. The owner or operator shall then either implement Option 1 in section 2.2.5.1 of this appendix or Option 2 in section 2.2.5.2 of this appendix.

2.2.5.1 Option 1

Within one week of the end of the calendar quarter for which the flow-to-load (or GHR) evaluation indicates noncompliance, investigate and troubleshoot each flow monitor for which E_f has been found to be above the applicable limit. Evaluate the results of each investigation as follows:

(a) If the investigation fails to uncover a problem with the flow monitor, a RATA shall be performed in accordance with Option 2 in section 2.2.5.2 of this appendix.

(b) If a problem with the flow monitor is identified through the investigation (including the need to re-linearize the monitor by changing the polynomial coefficients), corrective actions shall be taken. All corrective actions (e.g., non-routine maintenance, repairs, major component replacements, re-linearization of the monitor, etc.) shall be documented in the operation and maintenance records for the monitor. Data from the monitor shall remain invalid until a probationary calibration error test of the monitor is passed following completion of all corrective actions, at which point data from the monitor are conditionally valid. The owner or operator shall then either: (1) complete the abbreviated flow-to-load test in section 2.2.5.3 of this appendix; or (2) perform a 3-level recertification RATA according to the recertification test period and data validation procedures of § 75.20(b)(3), if the corrective action has affected the linearity of the flow monitor (e.g., by requiring changes to the flow monitor polynomial coefficients).

2.2.5.2 Option 2

Perform a single-load RATA (at a load designated as normal under section 6.5.2.1 of appendix A to this part) of each flow monitor for which E_f is outside of the applicable limit. Data from the monitor remain invalid until the required RATA has been successfully completed.

2.2.5.3 Abbreviated Flow-to-Load Test

The following abbreviated flow-to-load test may be performed after any documented repair, component replacement, or other corrective maintenance to a flow monitor (except for changes affecting the linearity of the flow monitor, such as adjusting the flow monitor coefficients) to demonstrate that the repair, replacement, or other maintenance has not significantly affected the monitor's ability to accurately measure the stack gas volumetric flow rate. Data from the monitoring system are considered invalid from the hour of commencement of the repair, replacement, or maintenance until the hour in which a probationary calibration error test is passed following completion of the repair, replacement, or maintenance and any associated adjustments to the monitor. The abbreviated flow-to-load test shall be completed within 168 unit operating hours of the probationary calibration error test (or, for peaking units, within 30 unit operating days, if that is less restrictive). Data from the monitor are considered to be conditionally valid (as defined in § 72.2 of this chapter), beginning with the hour of the probationary calibration error test.

Operate the unit(s) in such a way as to reproduce, as closely as practicable, the exact conditions at the time of the most recent normal-load flow RATA. To achieve this, it is recommended that the load be held constant to within ±5.0 percent of the average load during the RATA and that the diluent gas (CO_2 or O_2) concentration be maintained within ±0.5 percent CO_2 or O_2 of the average diluent concentration during the RATA. For common stacks, to the extent practicable, use the same combination of units and load levels that were used during the RATA. When the process parameters have been set, record a minimum of 6 and a maximum of 12 consecutive hourly average flow rates, using the flow monitor(s) for which E_f was outside the applicable limit. For peaking units, a minimum of 3 and a maximum of 12 consecutive hourly average flow rates are required. Also record the corresponding hourly load values and, if applicable, the hourly diluent gas concentrations. Calculate the flow-to-load ratio (or GHR) for each hour in the test hour period, using Equation B–1 or B–1a. Determine E_h for each hourly flow-to-load ratio (or GHR), using Equation B–2 of this appendix and then calculate E_f, the arithmetic average of the E_h values.

The results of the abbreviated flow-to-load test shall be considered acceptable, and no further action is required if the value of E_f does not exceed the applicable limit specified in section 2.2.5.1 of this appendix. All conditionally valid data recorded by the flow monitor shall be considered quality assured, beginning with the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test. However, if E_f is outside the applicable limit, all conditionally valid data recorded by the flow monitor shall be considered invalid back to the hour of the probationary calibration error test that preceded the abbreviated flow-to-load test, and a single-load RATA is required in accordance with section 2.2.5.2 of this appendix. If the flow monitor must be re-linearized, however, a 3-load RATA is required, in accordance with the recertification test period and data validation procedures of § 75.20(b)(3).

2.3 Semiannual and Annual Assessments

For each primary and redundant backup continuous emission monitoring system, perform relative accuracy assessments either

semiannually or annually, as specified in subsection 2.3.1.1 or 2.3.1.2, below, for the type of test and the performance achieved. This requirement is effective as of the calendar quarter following the calendar quarter in which the continuous emission monitoring system is provisionally certified. A summary chart showing the frequency with which a relative accuracy test audit must be performed, depending on the accuracy achieved, is located at the end of this appendix in Figure 2.

2.3.1 Relative Accuracy Test Audit (RATA)

2.3.1.1 Standard RATA Frequencies

Except as otherwise specified in § 75.21(a)(6) or (a)(7) or in section 2.3.1.2 of this appendix, perform relative accuracy test audits semiannually, i.e., once every two successive QA operating quarters for each primary and redundant backup SO_2 pollutant concentration monitor, flow monitor, CO_2 pollutant concentration monitor (including O2 monitors used to determine CO_2 emissions), moisture monitoring system, NO_X-diluent continuous emission monitoring system, or SO_2-diluent continuous emission monitoring system used by units with a Phase I qualifying technology for the period during which the units are required to monitor SO_2 emission removal efficiency, from January 1, 1997 through December 31, 1999. A QA operating quarter is a calendar quarter in which the unit operates for at least 168 hours or, for a common stack or bypass stack, a calendar quarter in which flue gases are discharged through the stack for at least 168 hours. A calendar quarter that does not qualify as a QA operating quarter shall be excluded in determining the deadline for the next RATA. No more than eight successive calendar quarters shall elapse after the quarter in which a RATA was last performed without a subsequent RATA having been conducted. If a RATA has not been completed by the end of the eighth calendar quarter since the quarter of the last RATA, then the RATA must be completed within a 720 unit operating hour grace period (as provided in section 2.3.3 of this appendix) following the end of the eighth successive elapsed calendar quarter, or data from the CEMS will become invalid.

The relative accuracy test audit frequency of a CEMS may be reduced, as specified in subsection 2.3.1.2, below, for primary or redundant backup monitoring systems which qualify for less frequent testing. Perform all required RATAs in accordance with the applicable procedures and provisions in sections 6.5 through 6.5.2.2 of appendix A to this part and subsections 2.3.1.3 and 2.3.1.4 of this appendix.

2.3.1.2 Reduced RATA Frequencies

Relative accuracy test audits of primary and redundant backup SO_2 pollutant concentration monitors, CO_2 pollutant concentration monitors (including O2 monitors used to determine CO_2 emissions), moisture monitors, flow monitors, or NO_X-diluent or SO_2-diluent monitoring systems may be performed annually (i.e., once every four successive QA operating quarters, rather than once every two successive QA operating quarters) if any of the following conditions are met for the specific monitoring system involved: (1) the relative accuracy during the audit of an SO_2 or CO_2 pollutant concentration monitor (including an O2 pollutant monitor used to measure CO_2 using the procedures in appendix F to this part) or of a NO_X-diluent or SO_2-diluent continuous emissions monitoring system is ≤7.5 percent; (2) prior to January 1, 2000, the relative accuracy during the audit of a flow monitor is ≤10.0 percent at each operating level tested; (3) on and after January 1, 2000, the relative accuracy during the audit of a flow monitor is ≤7.5 percent at each operating level tested; (4) on low flow (≤10.0 fps) stacks/ducts, when flow monitor achieves a relative accuracy ≤7.5 percent (10.0 percent if prior to January 1, 2000) during the audit or when the monitor mean, calculated using Equation A–7 in appendix A to this part, is within ±1.5 fps of the reference method mean; (5) on low SO_2 emitting units (average SO_2 concentrations 250 ppm, or average SO_2 emission rate 0.500 lb/mmBtu for SO_2-diluent continuous emission monitoring systems), when the CEMS achieves a relative accuracy ≤7.5 percent during the audit or when the monitor mean value from the RATA is within ± 12 ppm (or 0.025 lb/mmBtu for SO_2-diluent continuous emission monitoring systems) of the reference method mean value; (6) on low NO_X emitting units (average NO_X emission rate ≤0.200 lb/mmBtu), when the NO_X continuous emission monitoring system achieves a relative accuracy ≤7.5 percent or when the monitoring system mean value from the RATA, calculated using Equation A–7 in appendix A to this part, is within ± 0.015 lb/mmBtu of the reference method mean value; (7) for a CO_2 or O2 monitor, when the mean difference between the reference method values from the RATA and the corresponding monitor values is within ±0.7 percent CO_2 or O2; and (8) when the relative accuracy of a continuous moisture monitoring system is ≤7.5 percent or when the mean difference between the reference method values from the RATA and the corresponding monitoring system values is within ±0.7 percent H2O.

2.3.1.3 RATA Load Levels

(a) For SO_2 pollutant concentration monitors, CO_2 pollutant concentration monitors (including O_2 monitors used to determine CO_2 emissions), moisture monitoring systems, and SO_2-diluent and NO_X-diluent monitoring systems, the required RATA tests shall be done at the load level designated as normal under section 6.5.2.1 of appendix A to this part. If two load levels are designated as normal, the required RATA(s) may be done at either load level.

(b) For flow monitors installed on peaking units and bypass stacks, all required relative accuracy test audits shall be single-load audits at the normal load, as defined in section 6.5.2.1 of appendix A to this part.

(c) For all other flow monitors, the RATAs shall be performed as follows. When a flow monitor qualifies for an annual RATA frequency under section 2.3.1.2 of this appendix, the annual RATA shall be done at the two most frequently used load levels, as determined under section 6.5.2.1 of appendix A to this part. The annual 2-load flow RATA may be performed alternately with a single-load flow RATA at the most frequently used (normal) load level if the flow monitor is on a semiannual RATA frequency. In addition, a single-load flow RATA, at the most frequently used load level, may be performed in lieu of the 2-load RATA if, for the four QA operating quarters prior to the quarter in which the RATA is performed, the historical load frequency distribution determined under section 6.5.2.1 of appendix A to this part shows that the unit has operated at the most frequently used load level for ≤85.0 percent of the time. Finally, a 3-load RATA, at the low-, mid-, and high-load levels, determined under section 6.5.2.1 of appendix A to this part, shall be performed at least once in every period of five consecutive calendar years, and a 3-load RATA is required whenever a flow monitor is re-linearized, i.e., when one or more of its polynomial coefficients are changed. For all multi-level flow audits, the audit points at adjacent load levels (e.g., mid and high) shall be separated by no less than 25.0 percent of the ''range of operation,'' as defined in section 6.5.2.1 of appendix A to this part.

2.3.1.4 Number of RATA Attempts

The owner or operator may perform as many RATA attempts as are necessary to achieve the desired relative accuracy test audit frequencies and/or bias adjustment factors. However, the data validation procedures in section 2.3.2 of this appendix must be followed.

2.3.2 Data Validation

(a) A routine quality assurance RATA shall not commence if the monitoring system is operating out-of-control with respect to any of the daily and quarterly quality assurance assessments required by sections 2.1 and 2.2 of this appendix or with respect to the additional calibration error test requirements in section 2.1.3 of this appendix.

(b) All RATAs must be done hands-off, as follows. No adjustment of the monitor's calibration is permitted prior to or during the RATA test period, other than the adjustments described in section 2.1.3 of this appendix. The non-routine calibration adjustments described in section 2.1.3 of this appendix are permitted only prior to the RATA, not during the test period. For 2-level and 3-level flow monitor audits, no linearization of the monitor is permitted in-between load levels.

(c) For single-load RATAs, if a daily calibration error test is failed during a RATA test period, prior to completing the test, the RATA is invalidated and must be repeated. Data from the monitor are invalidated prospectively from the hour of the failed calibration error test until the hour of completion of a subsequent successful RATA. The subsequent RATA shall not be re-commenced until the monitor has successfully passed a calibration error test in accordance with section 2.1.3 of this appendix. For multiple-load flow RATAs, each load level is treated as a separate RATA (i.e., when a calibration error test is failed prior to completing the RATA at a particular load level, only the RATA at that load level is invalidated; the results of any previously-passed RATA(s) at the other load level(s) are unaffected).

(d) If a RATA is failed (that is, if the relative accuracy exceeds the applicable

specification in section 3.3 of appendix A to this part) or if the RATA is aborted prior to completion due to a problem with the CEMS, then all emission data from the CEMS are invalidated prospectively from the hour in which the RATA is failed or aborted. Data from the CEMS remain invalid until the hour of completion of a subsequent RATA that meets the applicable specification in section 3.3 of appendix A to this part. Note that a monitoring system shall not be considered out-of-control when a RATA is aborted for a reason other than monitoring system malfunction (see paragraph (g) of this section).

(e) For a 2-level or 3-level flow RATA, if, at any load level, a RATA is failed or aborted due to a problem with the CEMS, the RATA at that load level must be repeated. Data from the flow monitor are invalidated from the hour in which the test is failed or aborted and remain invalid until the successful completion of a RATA at the failed load level. RATA(s) that were previously passed at the other load level(s) do not have to be repeated unless the flow monitor must be re-linearized following the failed or aborted test. If the monitor is re-linearized, a subsequent 3-load RATA is required.

(f) For a CO_2 pollutant concentration monitor (or an O_2 monitor used to measure CO_2 emissions) which also serves as the diluent component in a NO_X-diluent (or SO_2-diluent) monitoring system, if the CO_2 (or O_2) RATA is failed, then both the CO_2 (or O_2) monitor and the associated NO_X-diluent (or SO_2-diluent) system are considered out-of-control until the hour of completion of subsequent hands-off RATAs which demonstrate that both systems have met the applicable relative accuracy specifications in sections 3.3.2 and 3.3.3 of appendix A to this part. The out-of-control period for each monitoring system begins with the hour of completion of the failed CO_2 (or O_2) monitor RATA.

(g) For each monitoring system, report the results of all completed and partial RATAs that affect data validation (i.e., all completed, passed RATAs; all completed, failed RATA; and all RATAs aborted due to a problem with the CEMS) in the quarterly report required under § 75.64. Note that RATA attempts that are aborted or invalidated due to problems with the reference method or due to operational problems with the affected unit(s) need not be reported. Such runs do not affect the validation status of emission data recorded by the CEMS. In addition, aborted RATA attempts that are part of the process of optimizing a monitoring system's performance do not have to be reported, provided that, in the period extending from the hour in which the test is aborted to the hour of commencement of the next RATA attempt: (1) no corrective maintenance or reprogramming of the monitoring system is done; and (2) only the calibration adjustments allowed under section 2.1.3 of this appendix are made. However, a record of all RATAs and RATA attempts (whether reported or not) must be kept on-site as part of the official test log for each monitoring system.

(h) Each time that a hands-off RATA of an SO_2 pollutant concentration monitor, a NO_X-diluent monitoring system, or a flow monitor is successfully completed, perform a bias test in accordance with section 7.6.4 of appendix A to this part. Apply the appropriate bias adjustment factor to the reported SO_2, NO_X, or flow rate data, in accordance with section 7.6.5 of appendix A to this part.

(i) Failure of the bias test does not result in the monitoring system being out-of-control.

2.3.3 RATA Grace Period

The owner or operator has a grace period of 720 consecutive unit operating hours in which to complete the required RATA for a particular CEMS, whenever: (a) a required RATA has not been performed by the end of the QA operating quarter in which it is due; (b) five consecutive calendar years have elapsed without a required 3-load flow RATA having been conducted; (c) an SO_2 RATA has not been completed by the end of the calendar quarter in which the annual usage of fuel(s) with a total sulfur content greater than the total sulfur content of natural gas exceeds 480 hours, for a unit which is conditionally exempted under § 75.21(a)(7) from the SO_2 RATA requirements of this part; or (d) eight successive calendar quarters have elapsed, following the quarter in which a RATA was last performed, without a subsequent RATA having been done, due to: (1) infrequent operation of the unit(s); (2) frequent combustion of fuel(s) with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤0.05 percent sulfur by weight) (SO_2 monitors, only); or (3) a combination of factors (1) and (2).

Except for SO_2 monitoring system RATAs, the grace period shall begin with the first unit operating hour following the calendar quarter in which the required RATA was due. For SO_2 monitor RATAs, the grace period shall begin with the first unit operating hour in which fuel with a total sulfur content greater than the total sulfur content of natural gas (i.e., >0.05 percent sulfur by weight) is burned in the unit(s), following the quarter in which the required RATA is due. Data validation during a RATA grace period shall be done in accordance with the applicable provisions in section 2.3.2 of this appendix.

If, at the end of the 720 unit operating hour grace period, the RATA has not been completed, data from the monitoring system shall be invalid, beginning with the first unit operating hour following the expiration of the grace period. Data from the CEMS remain invalid until the hour of completion of a subsequent hands-off RATA. Note that when a RATA (or RATAs, if more than one attempt is made) is done during a grace period in order to satisfy a RATA requirement from a previous quarter (i.e., for reasons (a), (b), or (d) in this section), the deadline for the next RATA shall be determined from the quarter in which the RATA was due, not from the quarter in which the grace period is used.

2.3.4 Bias Adjustment Factor

Except as otherwise specified in section 7.6.5 of appendix A to this part, if an SO_2 pollutant concentration monitor, flow monitor, or NO_X continuous emission monitoring system fails the bias test specified in section 7.6 of appendix A to this part, use the bias adjustment factor given in Equations A–11 and A–12 of appendix A to this part to adjust the monitored data.

2.4 Recertification, Quality Assurance, and RATA Deadlines

When a significant change is made to a monitoring system such that recertification of the monitoring system is required in accordance with § 75.20(b), a recertification test (or tests) must be performed to ensure that the CEMS continues to generate valid data. In many instances, a required recertification test is the same type of test as one of the routine, periodic quality assurance tests required by this appendix (e.g., a linearity test or a RATA). When this occurs, the recertification test may be used to satisfy the quality assurance test requirement of this appendix. For example, if, for a particular change made to a CEMS, one of the required recertification tests is a linearity check and the linearity test is successful, then, unless another recertification event occurs in that same QA operating quarter, it would not be necessary to perform a subsequent linearity test of the CEMS in that quarter. For this reason, EPA recommends that owners or operators coordinate component replacements, system upgrades, and other events that may require recertification, to the extent practicable, with the periodic quality assurance testing required by this appendix. When a quality assurance test is done for the dual purpose of recertification and routine quality assurance, the applicable data validation procedures in § 75.20(b)(3) shall be followed in lieu of the procedures in this appendix.

Except as provided in section 2.3.3 of this appendix, whenever a successful RATA of a gas monitor or a successful 2-load or 3-load RATA of a flow monitor is performed (irrespective of whether the RATA is done to satisfy a recertification requirement or to meet the quality assurance requirements of this appendix, or both), the deadline for the next RATA shall be established based upon the date and time of completion of the RATA and the relative accuracy percentage obtained. For 2-load and 3-load flow RATAs, use the highest percentage relative accuracy at any of the loads to determine the deadline for the next RATA. The results of a single-load flow RATA may be used to establish a RATA deadline when: (1) the single-load flow RATA is specifically required under section 2.3.1.3(b) of this appendix (for flow monitors installed on peaking units and bypass stacks); or (2) the single-load RATA is allowed for a unit that has operated at the most frequently used load level for ≥85.0 percent of the time, under section 2.3.1.3(c) of this appendix. No other single-load flow RATA may be used to establish an annual RATA frequency; however, a 2-load flow RATA may be performed in place of any required single-load RATA, in order to establish an annual RATA frequency.

2.5 Other Audits

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61. Figures 1 and 2 at the end of appendix B are revised to read as follows:

FIGURE 1.—QUALITY ASSURANCE TEST REQUIREMENTS

Test	QA test frequency requirements		
	Daily*	Quarterly*	Semiannual*
Calibration Error (2 pt.)	✔		
Interference (flow)	✔		
Flow-to-Load Ratio		✔	
Leak Check (DP flow monitors)		✔	
Linearity (3 pt.)		✔	
RATA (SO_2, NO_X, CO_2, percent H_2O) [1]		✔	
RATA (flow) [1, 2]			✔

*For monitors on bypass stack/duct, ''daily'' means bypass operating days, only. ''Quarterly'' means once every QA operating quarter. ''Semiannual'' means once every two QA operating quarters.

[1] Conduct RATA annually (i.e., once every four QA operating quarters), if monitor meets accuracy requirements to qualify for less frequent testing.

[2] For flow monitors installed on peaking units and bypass stacks, conduct all RATAs at a single, normal load. For other flow monitors, conduct RATAs at the two most frequently used loads. Alternating single-load and 2-load RATAs may be done if a monitor is on a semiannual frequency. A single-load RATA may be done in lieu of a 2-load RATA if, in the past four QA operating quarters, the unit has operated at one load level for ≥ 85.0 percent of the time. A 3-load RATA is required at least once in every period of five consecutive calendar years and whenever a flow monitor is re-linearized.

FIGURE 2.—RELATIVE ACCURACY TEST FREQUENCY INCENTIVE SYSTEM

RATA	Semiannual[1] (percent)	Annual[1]
SO_2	7.5% < RA ≤ 10.0% or ± 15.0 ppm [2]	RA ≤ 7.5.% or ± 12.0 ppm [2]
SO_2/diluent	7.5% < RA ≤ 10.0% or ± 0.030 lb/mmBtu [2]	RA ≤ 7.5% or ± 0.025 lb/mmBtu [2]
NO_X/diluent	7.5% < RA ≤ 10.0% or ± 0.020 lb/mmBtu [2]	RA ≤ 7.5% or ±0.015 lb/mmBtu [2]
Flow (Phase I)	10.0% < RA ≤ 15.0% or ± 1.5 fps [2]	RA ≤ 10.0%
Flow (Phase II)	7.5% < RA ≤ 10.0% or ± 1.5 fps [2]	RA ≤ 7.5%
CO_2/O_2	7.5% < RA ≤ 10.0% or ± 1.0% CO_2/O_2 [2]	RA ≤ 7.5% or ± 0.7% CO_2/O_2 [2]
Moisture	7.5% < RA ≤ 10.0% or ± 1.0% H_2O_2	RA ≤ 7.5% or ± 0.7% H_2O_2

[1] The deadline for the next RATA is the end of the second (if semiannual) or fourth (if annual) successive QA operating quarter following the quarter in which the CEMS was last tested. Exclude calendar quarters in which the unit operates for < 168 hours (or, for common stacks and bypass stacks, exclude quarters in which gases discharge through the stack for < 168 hours) in determining the RATA deadline. For SO_2 monitors, QA operating quarters in which only fuel with a total sulfur content no greater than the total sulfur content of natural gas (i.e., ≤ 0.05 percent sulfur by weight) is combusted may also be excluded. However, the exclusion of calendar quarters is limited as follows: the deadline for the next RATA shall be no more than 8 calendar quarters after the quarter in which a RATA was last performed.

[2] The difference between monitor and reference method mean values applies to moisture monitors, CO_2, and O_2 monitors, low emitters, or low flow, only.

62. Section 2 of appendix C to part 75 is amended by revising sections 2.1 and 2.2.1 and by revising Table C–1 to read as follows:

Appendix C to Part 75—Missing Data Estimation Procedures

* * * * *

2. Load-Based Procedure for Missing Flow Rate and NO_X Emission Rate Data

2.1 Applicability

This procedure is applicable for data from all affected units for use in accordance with the provisions of this part to provide substitute data for volumetric flow rate (scfh) and NO_X emission rate (in lb/mmBtu).

2.2 * * *

2.2.1 For a single unit, establish 10 operating load ranges defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MWge), as shown in Table C–1. (Do not use integrated hourly gross load in MW-hr.) For units sharing a common stack monitored with a single flow monitor, the load ranges for flow (but not for NO_X) may be broken down into 20 operating load ranges in increments of 5.0 percent of the combined maximum hourly average gross load of all units utilizing the common stack. If this option is selected, the twentieth (uppermost) operating load range shall include all values greater than 95.0 percent of the maximum hourly average gross load. For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity or for a unit for which hourly average gross load in MWge is not recorded separately, use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia) instead of MWge. Indicate a change in the number of load ranges or the units of loads to be used in the precertification section of the monitoring plan.

TABLE C–1.—DEFINITION OF OPERATING LOAD RANGES FOR LOAD-BASED SUBSTITUTION DATA PROCEDURES

Operating load range	Hourly gross load*
1	0–10
2	>10–20
3	>20–30
4	>30–40
5	>40–50
6	>50–60

TABLE C–1.—DEFINITION OF OPERATING LOAD RANGES FOR LOAD-BASED SUBSTITUTION DATA PROCEDURES—Continued

Operating load range	Hourly gross load*
7	>60–70
8	>70–80
9	>80–90
10	>90

*Percent of maximum hourly gross load or maximum hourly gross steam load (percent).

* * * * *

63. Section 1 of appendix D to part 75 is amended by revising section 1.1 to read as follows:

Appendix D to Part 75—Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units

1. Applicability

1.1 This protocol may be used in lieu of continuous SO_2 pollutant concentration and flow monitors for the purpose of determining hourly SO_2 emissions and heat input from:

(1) gas-fired units, as defined in § 72.2 of this chapter; or (2) oil-fired units, as defined in § 72.2 of this chapter. This optional SO_2 emissions data protocol contains procedures for conducting oil sampling and analysis in section 2.2 of this appendix; the procedures for oil sampling may be used for any gas-fired unit or oil-fired unit. In addition, this optional SO_2 emissions data protocol contains three procedures for determining SO_2 emissions due to the combustion of gaseous fuels having a total sulfur content no greater than 20 grains per 100 standard cubic foot.

* * * * *

64. Section 2 of appendix D to part 75 is amended by:

a. Revising section 2.1 *Flowmeter Measurements*;

b. Revising sections 2.2, 2.2.1, 2.2.3, 2.2.4, 2.2.6, and 2.2.8; and removing and reserving section 2.2.2;

c. Revising sections 2.3, 2.3.1, 2.3.1.3, 2.3.2; redesignating section 2.3.1.4 as 2.3.1.4.1 and revising it; and adding sections 2.3.1.4.1, 2.3.1.4.2, 2.3.1.4.3, and 2.3.3; and

d. Revising section 2.4.1; removing section 2.4.2; redesignating sections 2.4.3, 2.4.3.1, 2.4.3.2, and 2.4.3.3 as 2.4.2, 2.4.2.1, 2.4.2.2, and 2.4.2.3, respectively; revising newly designated sections 2.4.2, 2.4.2.1, and 2.4.2.3; and redesignating section 2.4.4 as 2.4.3.

2. Procedure

2.1 Flowmeter Measurements

For each hour when the unit is combusting fuel, measure and record the flow rate of fuel combusted by the unit, except as provided for gas in section 2.1.4.1 of this appendix. Measure the flow rate of fuel with an in-line fuel flowmeter, and automatically record the data with a data acquisition and handling system, except as provided in section 2.1.4 of this appendix.

2.1.1 Measure the flow rate of each fuel entering and being combusted by the unit. If a portion of the flow greater than 5.0 percent of the annual average flow rate from the main pipe is diverted from the unit without being burned and that diversion occurs downstream of the fuel flowmeter, an additional in-line fuel flowmeter is required to account for the unburned fuel. In this case, record the flow rate of each fuel combusted by the unit as the difference between the flow measured in the pipe leading to the unit and the flow in the pipe diverting fuel away from the unit. The hourly average proportion of flow rate from the pipe diverting fuel away from the unit to total fuel usage by the unit may be determined by using fuel usage data from fuel flowmeters in a previous year or by using a method approved by the Administrator under the provisions of § 75.66(i).

2.1.2 Install and use fuel flowmeters meeting the requirements of this appendix in a pipe going to each unit, or install and use a fuel flowmeter in a common pipe header (i.e., a pipe carrying fuel for multiple units). However, the use of a fuel flowmeter in a common pipe header and the provisions of sections 2.1.2.1 and 2.1.2.2 of this appendix are not applicable to any unit that is using the provisions of subpart H of this part to monitor, record, and report NO_X mass emissions under a state or federal NO_X mass emission reduction program. For all other units, if the fuel flowmeter is installed in a common pipe header, do one of the following:

2.1.2.1 Measure the fuel flow rate in the common pipe, and combine SO_2 mass emissions for the affected units for recordkeeping and compliance purposes; or

2.1.2.2 Provide information satisfactory to the Administrator on methods for apportioning SO_2 mass emissions and heat input to each of the affected units demonstrating that the method ensures complete and accurate accounting of the actual emissions from each of the affected units included in the apportionment and all emissions regulated under this part. The information shall be provided to the Administrator through a petition submitted by the designated representative under § 75.66. Satisfactory information includes apportionment, using fuel flow measurements, the ratio of hourly integrated gross load (in MWe-hr) in each unit to the total load for all units receiving fuel from the common pipe header, or the ratio of hourly steam flow (in 1000 lb) at each unit to the total steam flow for all units receiving fuel from the common pipe header, and documentation that shows the provisions of sections 2.1.5 and 2.1.6 of this appendix have been met for the fuel flowmeter used in the apportionment.

2.1.3 For a gas-fired unit or an oil-fired unit that continuously or frequently combusts a supplemental fuel for flame stabilization or safety purposes, measure the flow rate of the supplemental fuel with a fuel flowmeter meeting the requirements of this appendix.

2.1.4 Situations in Which Certified Flowmeter Is Not Required

2.1.4.1 Start-up or Ignition Fuel

For an oil-fired unit that uses gas solely for start-up or burner ignition or a gas-fired unit that uses oil solely for start-up or burner ignition, a flowmeter for the start-up fuel is not required. Estimate the volume of oil combusted for each start-up or ignition either by using a fuel flowmeter or by using the dimensions of the storage container and measuring the depth of the fuel in the storage container before and after each start-up or ignition. A fuel flowmeter used solely for start-up or ignition fuel is not subject to the calibration requirements of sections 2.1.5 and 2.1.6 of this appendix. Gas combusted solely for start-up or burner ignition does not need to be measured separately.

2.1.4.2 Gas Flowmeter Used for Commercial Billing

A gas flowmeter used for commercial billing of pipeline natural gas may be used to measure, record, and report hourly fuel flow rate. A gas flowmeter used for commercial billing of pipeline natural gas is not required to meet the certification requirements of section 2.1.5 of this appendix or the quality assurance requirements of section 2.1.6 of this appendix under the following circumstances: (1) the gas flowmeter is used for commercial billing under a contract, provided that the company providing the gas under the contract and each unit combusting the gas do not have any common owners and are not owned by subsidiaries or affiliates of the same company; (2) the designated representative reports hourly records of gas flow rate, heat input rate, and emissions due to combustion of pipeline natural gas; (3) the designated representative also reports hourly records of heat input rate for each unit, if the gas flowmeter is on a common pipe header, consistent with section 2.1.2 of this appendix; (4) the designated representative reports hourly records directly from the gas flowmeter used for commercial billing if these records are the values used, without adjustment, for commercial billing, or reports hourly records using the missing data procedures of section 2.4 of this appendix if these records are not the values used, without adjustment, for commercial billing; and (5) the designated representative identifies the gas flowmeter in the unit's monitoring plan.

2.1.5 For the purposes of initial certification, each fuel flowmeter used to meet the requirements of this protocol shall meet a flowmeter accuracy of ± 2.0 percent of the upper range value (i.e, maximum calibrated fuel flow rate) across the range of fuel flow rate to be measured at the unit. Flowmeter accuracy may be determined under section 2.1.5.1 of this appendix for initial certification either by design or by measurement under laboratory conditions by the manufacturer, by an independent laboratory, or by the owner or operator, or may be determined under section 2.1.5.2 of this appendix by measurement against a NIST traceable reference method.

2.1.5.1 Use the procedures in the following standards to verify flowmeter accuracy or design, as appropriate to the type of flowmeter: ASME MFC–3M–1989 with September 1990 Errata (''Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi''); ASME MFC–4M–1986 (Reaffirmed 1990), ''Measurement of Gas Flow by Turbine Meters''; American Gas Association Report No. 3, ''Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines'' (October 1990 Edition), Part 2: ''Specification and Installation Requirements'' (February 1991 Edition), and Part 3: ''Natural Gas Applications'' (August 1992 edition) (excluding the modified flow-calculation method in Part 3); Section 8, Calibration from American Gas Association Transmission Measurement Committee Report No. 7: Measurement of Gas by Turbine Meters (1985 Edition); ASME MFC–5M–1985 (''Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters''); ASME MFC–6M–1987 with June 1987 Errata (''Measurement of Fluid Flow in Pipes Using Vortex Flow Meters''); ASME MFC–7M–1987 (Reaffirmed 1992), ''Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles''; ISO 8316: 1987(E) ''Measurement of Liquid Flow in Closed Conduits—Method by Collection of

the Liquid in a Volumetric Tank''; American Petroleum Institute (API) Section 2, ''Conventional Pipe Provers,'' from Chapter 4 of the Manual of Petroleum Measurement Standards, October 1988 (Reaffirmed 1993); or MFC–9M–1988 with December 1989 Errata (''Measurement of Liquid Flow in Closed Conduits by Weighing Method'') for all other flowmeter types (incorporated by reference under § 75.6). The Administrator may also approve other procedures that use equipment traceable to National Institute of Standards and Technology standards. Document such procedures, the equipment used, and the accuracy of the procedures in the monitoring plan for the unit, and submit a petition signed by the designated representative under § 75.66(c). If the flowmeter accuracy exceeds ±2.0 percent of the upper range value, the flowmeter does not qualify for use under this part.

2.1.5.2 Alternatively, determine the flowmeter accuracy of a fuel flowmeter used for the purposes of this part by comparing it to the measured flow from a reference flowmeter which has been either designed according to the specifications of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix, or tested for accuracy during the previous 365 days, using a standard listed in section 2.1.5.1 of this appendix or other procedure approved by the Administrator under § 75.66 (all standards incorporated by reference under § 75.6). Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel flow rate readings over 20 minutes or longer for each meter at each of three different flow rate levels. The three flow rate levels shall correspond to: (1) normal full unit operating load, (2) normal minimum unit operating load, and (3) a load point approximately equally spaced between the full and minimum unit operating loads. Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

$$ACC = \frac{|R - A|}{URV} \times 100$$

(Eq. D–1)

Where:

ACC = Flowmeter accuracy as a percentage of the upper range value, including all error from all parts of both flowmeters.

R = Average of the three flow measurements of the reference flowmeter.

A = Average of the three measurements of the flowmeter being tested.

URV = Upper range value of fuel flowmeter being tested (i.e. maximum measurable flow).

Notwithstanding the requirement for calibration of the reference flowmeter within 365 days prior to an accuracy test, when an in-place reference meter or prover is used, the reference meter calibration requirement may be waived if, during the previous in-place accuracy test with that reference meter, the reference flowmeter and the flowmeter being tested agreed to within ± 1.0 percent of each other at all levels tested. This exception to calibration and flowmeter accuracy testing requirements for the reference flowmeter shall apply for periods of no longer than five consecutive years (i.e., 20 consecutive calendar quarters).

2.1.5.3 If the flowmeter accuracy exceeds the specification in section 2.1.5 of this appendix, the flowmeter does not qualify for use for this appendix. Either recalibrate the flowmeter until the flowmeter accuracy is within the performance specification, or replace the flowmeter with another one that is demonstrated to meet the performance specification. Substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix until quality assured fuel flow data become available.

2.1.5.4 For purposes of initial certification, when a flowmeter is tested against a reference fuel flow rate (i.e., fuel flow rate from another fuel flowmeter under section 2.1.5.2 of this appendix or flow rate from a procedure according to a standard incorporated by reference under section 2.1.5.1 of this appendix), report the results of flowmeter accuracy tests using Table D–1 below.

TABLE D–1.—TABLE OF FLOWMETER ACCURACY RESULTS

Measurement level (percent of URV)	Run No.	Time of run (HHMM)	Candidate flowmeter reading	Reference flow reading	Percent accuracy (percent of URV)
Test number:__Test completion date [1]:__Test completion time [1]: __					
Reinstallation date [2] (for testing under 2.1.5.1 only):__ Reinstallation time [2]:__					
Unit or pipe ID: Component/System ID :					
Flowmeter serial number: Upper range value:					
Units of measure for flowmeter and reference flow readings:					
Low (Minimum) level	1				
__ percent [3] of URV	2				
	3				
	Average				
Mid-level	1				
__ percent [3] of URV	2				
	3				
	Average				
High (Maximum) level	1				
__ percent [3] of URV	2				
	3				
	Average				

[1] Report the date, hour, and minute that all test runs were completed.
[2] For laboratory tests not performed inline, report the date, hour, and minute that the fuel flowmeter was reinstalled following the test.
[3] It is required to test at least at three different levels, from minimum to maximum.

2.1.6 Quality Assurance

Test the accuracy of each fuel flowmeter prior to use under this part and at least once every four fuel flowmeter QA operating quarters thereafter. A ''fuel flowmeter QA operating quarter'' is a unit operating quarter in which the unit combusts the fuel measured by the fuel flowmeter for more than 168 hours. Notwithstanding these requirements, no more than 20 successive calendar quarters shall elapse after the quarter in which a fuel flowmeter was last tested for accuracy without a subsequent flowmeter accuracy test having been conducted. Test the flowmeter accuracy more frequently if required by manufacturer specifications.

Except for orifice-, nozzle-, and venturi-type flowmeters, perform the required flowmeter accuracy testing using the procedures in either section 2.1.5.1 or section 2.1.5.2 of this appendix. Each fuel flowmeter

must meet the accuracy specification in section 2.1.5 of this appendix.

For orifice-, nozzle-, and venturi-type flowmeters (that are designed according to the specifications of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6) or that have satisfied the initial certification test requirement by meeting an accuracy of 2.0 percent of the upper range value or less by comparison with another fuel flowmeter, following the procedures of section 2.1.5.2 of this appendix), perform a transmitter accuracy test once every four flowmeter QA operating quarters and a primary element visual inspection once every 12 calendar quarters, according to the procedures in sections 2.1.6.1 through 2.1.6.6 of this appendix for periodic quality assurance.

Notwithstanding the requirements of this section, if the procedures of section 2.1.7 of this appendix are performed during each fuel flowmeter QA operating quarter, subsequent to a required flowmeter accuracy test or transmitter accuracy test and primary element inspection, where applicable, those procedures may be used to meet the requirement for periodic quality assurance testing for a period of up to 20 calendar quarters from the previous accuracy test or transmitter accuracy test and primary element inspection, where applicable.

2.1.6.1 Transmitter or Transducer Accuracy Test for Orifice-, Nozzle-, and Venturi-Type Flowmeters

Calibrate the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. Check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at each of the following levels: the zero-level and at least two other levels across the range of readings on the transmitter or transducer corresponding to normal unit operation. Determine either the accuracy of each individual transmitter or transducer of the orifice-, nozzle-, or venturi-type flowmeter according to section 2.1.6.2 of this appendix, or determine the accuracy of the entire orifice-, nozzle-, or venturi-type flowmeter according to section 2.1.6.3 of this appendix.

2.1.6.2 Transmitter or Transducer Accuracy Calculation

Calculate the flowmeter accuracy at each level across the range of readings on the transmitter or transducer corresponding to normal unit operation by using the following equation:

$$ACC = \frac{|R - T|}{FS} \times 100$$

(Eq. D–1a)

Where:

ACC=Accuracy of the transmitter or transducer as a percentage of full-scale.

R=Reading of the NIST-traceable reference value (in milliamperes, inches of water, psi, or degrees).

T=Reading of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST-traceable reference value).

FS = Full-scale range of the transmitter or transducer being tested.

2.1.6.3 Total Flowmeter Accuracy Calculation

Use the transmitter or transducer accuracy calculated from Equation D–1a to determine if each individual transmitter or transducer meets an accuracy of ± 1.0 percent of its full-scale range at each level. If one or more of the transmitters or transducers does not meet this accuracy at each level, then either: (1) follow the data validation procedures in section 2.1.6.5 of this appendix, or (2) determine the total flowmeter accuracy at each level, i.e. error in the volumetric flow rate, including all transmitters or transducers and the primary element, using the following equation:

$$\frac{dq_v}{q_v} = \left(K^2 + \left[\frac{-dP_f}{2P_f}\right]^2 + \left[\frac{d\Delta P}{2\Delta P}\right]^2 + \left[\frac{dT_f}{2T_f}\right]^2 \right)^{1/2}$$

(Eq. D–1b)

Where:

dq_v/q_v=Error in the volumetric flow rate due to transmitter drift at a given level.

K=Original error resulting from installation of orifice (including all other variables). For an orifice-, nozzle-, or venturi-type flowmeter that was originally installed to the specifications of AGA Report No. 3 or ASME MFC–3M, as cited in section 2.1.5.1 of this appendix, an assumed value of 1.0 percent of the upper range value may be used for ''K'' if original error data or dimensional information from installation of the meter or other information on total installation error are not available.

dP_f=Average difference between static pressure transmitter reading(s) and reference static pressure reading(s) at a given level.

P_f=Average reference static pressure reading at a given level.

$d\Delta P$=Average difference between differential pressure transmitter reading(s) and reference differential pressure reading(s) at a given level.

ΔP = Average reference differential pressure reading at a given level.

dT_f=Average difference between temperature transmitter reading(s) and reference temperature reading(s) at a given level.

T_f=Average reference temperature reading at a given level.

Note: For gases, overall flow rate is directly related to pressure and is inversely related to temperature. Therefore, when performing this test on a gas fuel flowmeter, it is recommended that readings be entered into the equation at the following levels:

TABLE D–2—RECOMMENDED LEVELS FOR USING TRANSMITTER TEST RESULTS TO CALCULATE OVERALL GAS FLOWMETER ACCURACY

Level of total flow calculation	Level of static pressure reading	Level of differential pressure reading	Level of temperature reading
Low	Low	Low	High.
Mid	Mid	Mid	Mid.
High	High	High	Low.

If the overall flowmeter accuracy at each flow rate level is less than or equal to ± 2.0 percent of the upper range value of the fuel flowmeter, then the fuel flow rate data remain valid, and the data invalidation procedures of section 2.1.6.5 of this appendix are not required. If the overall flowmeter accuracy at any flow rate level is greater than ± 2.0 percent of the upper range value of the

fuel flowmeter, then data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed accuracy test and continuing until the date and hour of a successful accuracy test for all transmitters or transducers; during the period when data from the fuel flowmeter are considered invalid, provide data from another fuel flowmeter that meets the requirements of § 75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix.

2.1.6.4 Recordkeeping and Reporting of Transmitter or Transducer Accuracy Results

Record the accuracy of the orifice, nozzle, or venturi meter or its individual transmitters or transducers and keep this information in a file at the site or other location suitable for inspection. When testing individual orifice, nozzle, or venturi meter transmitters or transducers for accuracy, include the information displayed in Table D–3 below. At a minimum, record results for each transmitter or transducer at the zero-level and at least two other levels across the range of the transmitter or transducer readings that correspond to normal unit operation.

TABLE D–3.—TABLE OF FLOWMETER TRANSMITTER OR TRANSDUCER ACCURACY RESULTS

Measurement level (percent of full-scale)	Run number (if multiple runs) [2]	Run time (HHMM)	Transmitter/ Transducer input (pre-calibration)	Expected transmitter/ transducer output (reference)	Actual transmitter/ transducer output [3]	Percent accuracy (percent of full-scale)
Test number: __ Test completion date: __ Unit or pipe ID: __						
Flowmeter serial number: Component/System ID:						
Full-scale value: Units of measure [3]:						
Transducer/Transmitter Type (check one): __ Differential Pressure __ Static Pressure __ Temperature						
Low (Minimum) level. __ percent[1] of full-scale.						
Mid-level. __ percent[1] of full-scale. (If tested at more than 3 levels).						
2nd Mid-level. __ percent[1] of full-scale. (If tested at more than 3 levels).						
High (Maximum) level. __ percent[1] of full-scale.						

[1] At a minimum, it is required to test at zero-level and at least two other levels across the range of the transmitter or transducer readings corresponding to normal unit operation.
[2] It is required to test at least once at each level.
[3] Use the same units of measure for all readings (e.g., use degrees (°), inches of water (in H_2O), pounds per square inch (psi), or milliamperes (ma) for both transmitter or transducer readings and reference readings).

In addition, when testing the whole orifice, nozzle, or venturi meter for accuracy, record the information displayed in Table D–1 above. At a minimum, record the overall flowmeter accuracy results for the entire fuel flowmeter at the zero-level and at least two other levels across the range of normal unit operation.

Report the final result of the accuracy test (pass or fail) for the combination of all transmitters or transducers of the orifice, nozzle or venturi meter in the emissions report of the quarter in which the accuracy is determined, using the electronic format specified by the Administrator under § 75.64.

2.1.6.5 Failure of Transducer or Transmitter

Except as provided in section 2.1.6.3 of this appendix, if the accuracy during a calibration or test of an individual transmitter or transducer is greater than ±1.0 percent of the full-scale range for that transmitter or transducer at any level or if the individual transmitter or transducer fails to operate properly, recalibrate the transmitter or transducer or replace the transmitter or transducer with another one until the transmitter or transducer accuracy is less than or equal to ±1.0 percent of the full-scale range for that transmitter or transducer, consistent with sections 2.1.6.1 and 2.1.6.2 of this appendix. Data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed accuracy test (or a failure to operate properly) for any transmitter or transducer and continuing until the date and hour of an accuracy test for all transmitters or transducers in which all transmitters or transducers meet an accuracy of ±1.0 percent of the full-scale range for that transducer or transmitter. During this period, provide data from another fuel flowmeter that meets the requirements of § 75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix. Record and report test data and results, consistent with section 2.1.6.4 of this appendix and § 75.56 or § 75.59, as applicable.

2.1.6.6 Primary Element Inspection

Conduct a visual inspection of the orifice, nozzle, or venturi at least once every twelve calendar quarters. Notwithstanding this requirement, the procedures of section 2.1.7 of this appendix may be used to reduce the inspection frequency of the orifice, nozzle, or venturi to at least once every twenty calendar quarters. The inspection may be performed using a boroscope. If the visual inspection indicates that the orifice, nozzle, or venturi has become damaged or corroded, then: (1) replace the primary element with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6); (2) replace the primary element with another primary element, and demonstrate that the overall flowmeter accuracy meets the accuracy specification in section 2.1.5 of this appendix under the procedures of section 2.1.5.2 of this appendix; or (3) restore the damaged or corroded primary element to ''as new'' condition; determine the overall accuracy of the flowmeter, using either the specifications of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6); and retest the transmitters or transducers prior to providing quality assured data from the flowmeter. If the primary element size is changed, calibrate the transmitter or transducers consistent with the new primary element size. Data from the fuel flowmeter are considered invalid, beginning with the date and hour of a failed visual inspection and continuing until the date and hour when: (1) the damaged or corroded primary element is replaced with another primary element meeting the requirements of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6); (2) the damaged or corroded primary element is replaced, and the overall accuracy of the flowmeter is demonstrated to meet the accuracy specification in section 2.1.5 of this

appendix under the procedures of section 2.1.5.2 of this appendix; or (3) the restored primary element is installed to meet the requirements of American Gas Association Report No. 3 or ASME MFC–3M–1989, as cited in section 2.1.5.1 of this appendix (both standards incorporated by reference under § 75.6) and its transmitters or transducers are retested to meet the accuracy specification in section 2.1.6.4 of this appendix. During this period, provide data from another fuel flowmeter that meets the requirements of § 75.20(d) and section 2.1.5 of this appendix, or substitute for fuel flow rate using the missing data procedures in section 2.4.2 of this appendix.

2.1.7 Fuel Flow-to-Load Quality Assurance Testing for Certified Fuel Flowmeters

The procedures of this section may be used as an optional supplement to the quality assurance procedures in section 2.1.5.1, 2.1.5.2, 2.1.6.1, or 2.1.6.6 of this appendix when conducting periodic quality assurance testing of a certified fuel flowmeter. Note, however, that these procedures may not be used unless the 168 hour baseline data requirement of 2.1.7.2 has been met. If, following a flowmeter accuracy test or flowmeter transmitter test and primary element inspection, where applicable, the procedures of this section are performed during each subsequent flowmeter QA operating quarter, as defined in section 2.1.6 of this appendix (excluding the quarter(s) in which the baseline data are collected), then these procedures may be used to meet the requirement for periodic quality assurance for a period of up to 20 calendar quarters from the previous periodic quality assurance procedure(s) performed according to sections 2.1.5.1, 2.1.5.2, or 2.1.6.1 through 2.1.6.6 of this appendix. The procedures of this section are not required for any quarter in which a flowmeter accuracy test or a transmitter accuracy test and a primary element inspection, where applicable, are conducted. Notwithstanding the requirements of § 75.54(a) or § 75.57(a), as applicable, when using the procedures of this section, keep records of the test data and results from the previous flowmeter accuracy test under section 2.1.5.1 or 2.1.5.2 of this appendix, records of the test data and results from the previous transmitter or transducer accuracy test under section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters, and records of the previous visual inspection of the primary element required under section 2.1.6.6 of this appendix for orifice-, nozzle-, and venturi-type fuel flowmeters until the next flowmeter accuracy test, transmitter accuracy test, or visual inspection is performed, even if the previous flowmeter accuracy test, transmitter accuracy test, or visual inspection was performed more than three years previously.

2.1.7.1 Baseline Flow Rate-to-Load Ratio or Heat Input-to-Load Ratio

Determine R_{base}, the baseline value of the ratio of fuel flow rate to unit load, following each successful periodic quality assurance procedure performed according to section 2.1.5.1, 2.1.5.2, or 2.1.6.1 and 2.1.6.6 of this appendix. Establish a baseline period of data consisting, at a minimum, of 168 hours of quality assured fuel flowmeter data taken immediately after the most recent quality assurance procedure(s), during which only the fuel measured by the fuel flowmeter is combusted (i.e. only gas, only residual oil, or only diesel fuel is combusted by the unit). During the baseline data collection period, the owner or operator may exclude the following data as non-representative: (1) any hour in which the unit is ''ramping'' up or down, i.e., the load during the hour differs by more than 15.0 percent from the load in the previous or subsequent hour; and (2) any hour in which the unit load is in the lower 10.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part, unless operation in this lower portion of the range is considered normal for the unit. The baseline data must be obtained no later than the end of the second calendar quarter following the calendar quarter of the most recent quality assurance procedure for that fuel flowmeter. For orifice-, nozzle-, and venturi-type fuel flowmeters, if the fuel flow-to-load ratio is to be used as a supplement both to the transmitter accuracy test under section 2.1.6.1 of this appendix and to primary element inspections under section 2.1.6.6 of this appendix, then the baseline data must be obtained after both procedures are completed and no later than the end of the second calendar quarter following the calendar quarter of both the most recent transmitter or transducer test and the most recent primary element inspection for that fuel flowmeter. From these 168 (or more) hours of baseline data, calculate the baseline fuel flow rate-to-load ratio as follows:

$$R_{base} = \frac{Q_{base}}{L_{avg}}$$

(Eq. D–1c)

Where:

R_{base}=Value of the fuel flow rate-to-load ratio during the baseline period; 100 scfh/MWe or 100 scfh/klb per hour steam load for gas-firing; (lb/hr)/MWe or (lb/hr)/klb per hour steam load for oil-firing.

Q_{base}=Average fuel flow rate measured by the fuel flowmeter during the baseline period, 100 scfh for gas-firing and lb/hr for oil-firing.

L_{avg}=Average unit load during the baseline period, megawatts or 1000 lb/hr of steam.

In Equation D–1c, for a common pipe header, L_{avg} is the sum of the operating loads of all units that receive fuel through the common pipe header. For a unit that receives its fuel through multiple pipes, Q_{base} is the sum of the fuel flow rates for a particular fuel (i.e., gas, diesel fuel, or residual oil) from each of the pipes. Round off the value of R_{base} to the nearest tenth.

Alternatively, a baseline value of the gross heat rate (GHR) may be determined in lieu of R_{base}. The baseline value of the GHR, GHR_{base}, shall be determined as follows:

$$(GHR)_{base} = \frac{(\text{Heat Input})_{avg}}{L_{avg}} \times 1000$$

(Eq. D–1d)

Where:

$(GHR)_{base}$=Baseline value of the gross heat rate during the baseline period, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_{avg}$=Average (mean) hourly heat input rate recorded by the fuel flowmeter during the baseline period, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

L_{avg}=Average (mean) unit load during the baseline period, megawatts or 1000 lb/hr of steam.

Report the current value of R_{base} (or GHR_{base}) and the completion date of the associated quality assurance procedure in each electronic quarterly report required under § 75.64.

2.1.7.2 Data Preparation and Analysis

Evaluate the fuel flow rate-to-load ratio (or GHR) for each flowmeter QA operating quarter, as defined in section 2.1.6 of this appendix. At the end of each flowmeter QA operating quarter, use Equation D–1e in this appendix to calculate R_h, the hourly fuel flow-to-load ratio, for every quality assured hourly average fuel flow rate obtained with a certified fuel flowmeter.

$$R_h = \frac{Q_h}{L_h}$$

(Eq. D–1e)

Where:

R_h=Hourly value of the fuel flow rate-to-load ratio; 100 scfh/MWe, (lb/hr)/MWe, 100 scfh/1000 lb/hr of steam load, or (lb/hr)/1000 lb/hr of steam load.

Q_h = Hourly fuel flow rate, as measured by the fuel flowmeter, 100 scfh for gas-firing or lb/hr for oil-firing.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam.

For a common pipe header, L_h shall be the sum of the hourly operating loads of all units that receive fuel through the common pipe header. For a unit that receives its fuel through multiple pipes, Q_h will be the sum of the fuel flow rates for a particular fuel (i.e., gas, diesel fuel, or residual oil) from each of the pipes. Round off each value of R_h to the nearest tenth.

Alternatively, calculate the hourly gross heat rates (GHR) in lieu of the hourly flow-to-load ratios. If this option is selected, calculate each hourly GHR value as follows:

$$(GHR)_h = \frac{(\text{Heat Input})_h}{L_h} \times 1000$$

(Eq. D–1f)

Where:

$(GHR)_h$ = Hourly value of the gross heat rate, Btu/kwh or Btu/lb steam load.

$(\text{Heat Input})_h$ = Hourly heat input rate, as determined using the applicable equation in appendix F to this part, mmBtu/hr.

L_h = Hourly unit load, megawatts or 1000 lb/hr of steam.

Evaluate the calculated flow rate-to-load ratios (or gross heat rates) as follows. Perform a separate data analysis for each fuel flowmeter following the procedures of this

section. Base each analysis on a minimum of 168 hours of data. If, for a particular fuel flowmeter, fewer than 168 hourly flow-to-load ratios (or GHR values) are available, a flow-to-load (or GHR) evaluation is not required for that flowmeter for that calendar quarter.

For each hourly flow-to-load ratio or GHR value, calculate the percentage difference (percent D_h) from the baseline fuel flow-to-load ratio using Equation D–1g.

$$\%D_h = \frac{\left|R_{base} - R_h\right|}{R_{base}} \times 100$$

(Eq. D–1g)

Where:

$\%D_h$ = Absolute value of the percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

R_h = The hourly fuel flow rate-to-load ratio (or GHR).

R_{base} = The value of the fuel flow rate-to-load ratio (or GHR) from the baseline period, determined in accordance with section 2.1.7.1 of this appendix.

Consistently use R_{base} and R_h in Equation D–1g if the fuel flow-to-load ratio is being evaluated, and consistently use $(GHR)_{base}$ and $(GHR)_h$ in Equation D–1g if the gross heat rate is being evaluated.

Next, determine the arithmetic average of all of the hourly percent difference (percent D_h) values using Equation D–1h, as follows:

$$SO_{2_c} = \sum_{q=1}^{\text{the current quarter}} SO_{2_q}$$

(Eq. D–1h)

Where:

E_f = Quarterly average percentage difference between hourly flow rate-to-load ratios and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

$\%D_h$ = Percentage difference between the hourly fuel flow rate-to-load ratio and the baseline value of the fuel flow rate-to-load ratio (or hourly and baseline GHR).

q = Number of hours used in fuel flow-to-load (or GHR) evaluation.

When the quarterly average load value used in the data analysis is greater than 50 MWe (or 500 klb steam per hour), the results of a quarterly fuel flow rate-to-load (or GHR) evaluation are acceptable and no further action is required, if the quarterly average percentage difference (E_f) is no greater than 10.0 percent. When the arithmetic average of the hourly load values used in the data analysis is ≤ 50 MWe (or 500 klb steam per hour), the results of the analysis are acceptable if the value of E_f is no greater than 15.0 percent.

2.1.7.3 Optional Data Exclusions

If E_f is outside the limits in section 2.1.7.2 of this appendix, the owner or operator may re-examine the hourly fuel flow rate-to-load ratios (or GHRs) that were used for the data analysis and identify and exclude fuel flow-to-load ratios or GHR values for any non-representative fuel flow-to-load ratios or GHR values. Specifically, the R_h or $(GHR)_h$ values for the following hours shall be considered non-representative: (1) any hour in which the unit combusted another fuel in addition to the fuel measured by the fuel flowmeter being tested; (2) any hour for which the load differed by more than ± 15.0 percent from the load during either the preceding hour or the subsequent hour; and (3) any hour for which the unit load was in the lower 10.0 percent of the range of operation, as defined in section 6.5.2.1 of appendix A to this part, unless operation in this lower portion of the range is considered normal for the unit.

After identifying and excluding all non-representative hourly fuel flow-to-load ratios or GHR values, analyze the quarterly fuel flow rate-to-load data a second time.

2.1.7.4 Consequences of Failed Fuel Flow-to-Ratio Test

If E_f is outside the applicable limit in section 2.1.7.2 of this appendix (after analysis using any optional data exclusions under section 2.1.7.3 of this appendix), perform transmitter accuracy tests according to section 2.1.6.1 of this appendix for orifice-, nozzle-, and venturi-type flowmeters, or perform a fuel flowmeter accuracy test, in accordance with section 2.1.5.1 or 2.1.5.2 of this appendix, for each fuel flowmeter for which E_f is outside of the applicable limit. In addition, for an orifice-, nozzle-, or venturi-type fuel flowmeter, repeat the fuel flow-to-load ratio comparison of section 2.1.7.2 of this appendix using six to twelve hours of data following a passed transmitter accuracy test in order to verify that no significant corrosion has affected the primary element. If, for the abbreviated 6–to–12 hour test, the orifice-, nozzle-, or venturi-type fuel flowmeter is not able to meet the limit in section 2.1.7.2 of this appendix, then perform a visual inspection of the primary element according to section 2.1.6.6 of this appendix, and repair or replace the primary element, as necessary.

Substitute for fuel flow rate, for any hour when that fuel is combusted, using the missing data procedures in section 2.4.2 of this appendix, beginning with the first hour of the calendar quarter following the quarter for which E_f was found to be outside the applicable limit and continuing until quality assured fuel flow data become available. Following a failed flow rate-to-load or GHR evaluation, data from the flowmeter shall not be considered quality assured until the hour in which all required flowmeter accuracy tests, transmitter accuracy tests, visual inspections and diagnostic tests have been passed. Additionally, a new value of R_{base} or $(GHR)_{base}$ shall be established no later than two flowmeter QA operating quarters after the quarter in which the required quality assurance tests are completed (for orifice-, nozzle-, or venturi-type fuel flowmeters, a new value of R_{base} or $(GHR)_{base}$ shall only be established if both a transmitter accuracy test and a primary element inspection have been performed).

2.1.7.5 Test Results

Report the results of each quarterly flow rate-to-load (or GHR) evaluation, as determined from Equation D–1h, in the electronic quarterly report required under § 75.64. Table D–4 is provided as a reference on the type of information to be recorded under § 75.59 and reported under § 75.64.

TABLE D–4.—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST

Time period	
Baseline period	Quarter
Plant name:_____ State:_____ ORIS code:_____	
Unit/pipe ID #:_____ Fuel flowmeter component and system ID #s:____–____	
Calendar quarter (1st, 2nd, 3rd, 4th) and year:_____	
Range of operation:_____ to_____ MWe or klb steam/hr (indicate units)	
Completion date and time of most recent primary element inspection (orifice-, nozzle-, and venturi-type flowmeters only). ____/____/____ ____:____	Number of hours excluded from quarterly average due to co-firing different fuels:_____hrs.
Completion date and time of most recent flowmeter or transmitter accuracy test. ____/____/____ ____:____	Number of hours excluded from quarterly average due to ramping load:_____hrs.
Beginning date and time of baseline period	Number of hours in the lower 10.0 percent of the range of operation excluded from quarterly average:_____hrs.

TABLE D–4.—BASELINE INFORMATION AND TEST RESULTS FOR FUEL FLOW-TO-LOAD TEST—Continued

Time period	
Baseline period	Quarter
___/___/___ ___:___ End date and time of baseline period: ___/___/___ ___:___ Average fuel flow rate:_____ (100 scfh for gas and lb/hr for oil) ..... Average load:_____ (MWe or 1000 lb steam/hr)	Number of hours included in quarterly average:_____hrs. Quarterly percentage difference between hourly ratios and baseline ratio:_____ percent. Test result: pass, fail

Plant name:_____ State:_____ ORIS code:_____

Unit/pipe ID#:_____ Fuel flowmeter component and system ID #:____–____

Calendar quater (1st, 2nd, 3rd, 4th) and year:_____

Range of operation:_____ MWe or klb steam/hr (indicate units)

Time period	
Baseline fuel flow-to-load ratio:_____ Units of fuel flow-to-load:_____ Baseline GHR:_____ Units of fuel flow-to-load:_____ Number of hours excluded from baseline ratio or GHR due to ramping load:_____ hrs. Number of hours in the lower 10.0 percent of the range of operation excluded from baseline ratio or GHR:_____ hrs.	

2.2 Oil Sampling and Analysis

Perform sampling and analysis of oil to determine the percentage of sulfur by weight in the oil combusted by the unit. Calculate SO_2 mass emissions and heat input rate using the sulfur content, density, and gross calorific value (heat content), as described in the sections below and in Table D–5.

TABLE D–5.—OIL SAMPLING METHODS AND SULFUR, DENSITY AND GROSS CALORIFIC VALUE USED IN CALCULATIONS

Parameter	Sampling technique/frequency	Value used in calculations
Oil Sulfur Content..	Daily manual sampling	Highest sulfur content from previous 30 daily samples.
	Flow proportional/weekly composite..	Actual measured value.
	In storage tank (after addition of fuel to tank)	Actual measured value OR highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	Highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
Oil Density	Daily manual sampling	Actual measured value.
	Flow proportional/weekly composite..	Actual measured value.
	In storage tank (after addition of fuel to tank)	Actual measured value OR highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	Highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
Oil GCV	Daily manual sampling	Actual measured value.
	Flow proportional/weekly composite	Actual measured value.
	In storage tank (after addition of fuel to tank)	Actual measured value OR highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
	As delivered (in delivery truck or barge).[1]	Highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]

[1] Assumed values may only be used if sulfur content, gross calorific value, or density of each sample is no greater than the assumed value used to calculate emissions or heat input.

2.2.1 When combusting oil, sample the oil: (1) from the storage tank for the unit after each addition of oil to the storage tank, in accordance with section 2.2.4.2 of this appendix; (2) from the fuel lot in the shipment tank or container upon receipt of each oil delivery or from the fuel lot in the oil supplier's storage container, in accordance with section 2.2.4.3 of this appendix; (3) following the flow proportional sampling methodology in section 2.2.3 of this appendix; or (4) following the daily manual sampling methodology in section 2.2.4.1 of this appendix. For purposes of this appendix, a fuel lot of oil is the mass or volume of product oil from one source (supplier or pretreatment facility), intended as one shipment or delivery (ship load, barge load, group of trucks, discrete purchase of diesel fuel through pipeline, etc.), which meets the fuel purchase specifications for sulfur content and GCV. A storage tank is a container at a plant holding oil that is actually combusted by the unit, such that

blending of any other fuel with the fuel in the storage tank occurs from the time that the fuel lot is transferred to the storage tank to the time when the fuel is combusted in the unit.

2.2.2 [Reserved]

2.2.3 Flow Proportional Sampling

Conduct flow proportional oil sampling or continuous drip oil sampling in accordance with ASTM D4177–82 (Reapproved 1990), ''Standard Practice for Automatic Sampling of Petroleum and Petroleum Products'' (incorporated by reference under § 75.6), every day the unit is combusting oil. Extract oil at least once every hour and blend into a composite sample. The sample compositing period may not exceed 7 calendar days (168 hr). Use the actual sulfur content (and where density data are required, the actual density) from the composite sample to calculate the hourly SO_2 mass emission rates for each operating day represented by the composite sample. Calculate the hourly heat input rates for each operating day represented by the composite sample, using the actual gross calorific value from the composite sample.

2.2.4 Manual Sampling

2.2.4.1 Daily Samples

Representative oil samples may be taken from the storage tank or fuel flow line manually every day that the unit combusts oil according to ASTM D4057–88, ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products'' (incorporated by reference under § 75.6), provided that the highest fuel sulfur content recorded at that unit from the most recent 30 daily samples is used for the purpose of calculating SO_2 emissions under section 3 of this appendix. Use the gross calorific value measured from that day's samples to calculate heat input. If oil supplies with different sulfur contents are combusted on the same day, sample the highest sulfur fuel combusted that day.

2.2.4.2 Sampling from a Unit's Storage Tank

Take a manual sample after each addition of oil to the storage tank. No additional fuel shall be blended with the sampled fuel prior to combustion. Sample according to the single tank composite sampling procedure or all-levels sampling procedure in ASTM D4057–88, ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products'' (incorporated by reference under § 75.6). Use the sulfur content (and where required, the density) of either the most recent sample or one of the conservative assumed values described in section 2.2.4.3 of this appendix, to calculate SO_2 mass emission rate. Calculate heat input rate using the gross calorific value from either: (1) the most recent oil sample taken or (2) one of the conservative assumed values described in section 2.2.4.3 of this appendix.

2.2.4.3 Sampling from Each Delivery

Alternatively, an oil sample may be taken from the shipment tank or container upon receipt of each lot of fuel oil or from the supplier's storage container which holds the lot of fuel oil. For the purpose of this section, a lot is defined as a shipment or delivery (e.g., ship load, barge load, group of trucks, discrete purchase of diesel fuel through a pipeline, etc.) which meets the fuel purchase specifications for sulfur content and GCV. Oil sampling may be performed either by the owner or operator of an affected unit, an outside laboratory, or a fuel supplier, provided that samples are representative and that sampling is performed according to either the single tank composite sampling procedure or the all-levels sampling procedure in ASTM D4057–88, ''Standard Practice for Manual Sampling of Petroleum and Petroleum Products'' (incorporated by reference under § 75.6). Except as otherwise provided in this section 2.2.4.3, calculate SO_2 mass emission rate using the sulfur content (and where required, the density) from one of the two values below, and calculate heat input using the gross calorific value from one of the two following values: (1) the highest value sampled during the previous calendar year or (2) the maximum value indicated in the contract with the fuel supplier unit. Continue to use this assumed value unless and until the actual sampled sulfur content, density, or gross calorific value of a delivery exceeds the assumed value.

If the actual sampled sulfur content, gross calorific value, or density of an oil sample is greater than the assumed value for that parameter, then use the actual sampled value for sulfur content, gross calorific value, or density of fuel to calculate SO_2 mass emission rate or heat input rate as the new assumed sulfur content, gross calorific value, or density. Continue to use this new assumed value to calculate SO_2 mass emission rate or heat input rate unless and until: (1) it is superseded by a higher value from an oil sample; (2) a new contract with a higher maximum sulfur content, gross calorific value, or density is adopted, in which case the new contract value becomes the assumed value; or (3) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

* * * * *

2.2.6 Where the flowmeter records volumetric flow rate rather than mass flow rate, analyze oil samples to determine the density or specific gravity of the oil.

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2.2.8 Results from the oil sample analysis must be available no later than thirty calendar days after the sample is composited or taken. However, during an audit, the Administrator may require that the results of the analysis be available as soon as practicable, and no later than 5 business days after receipt of a request from the Administrator.

2.3 SO_2 Emissions from Combustion of Gaseous Fuels

Account for the hourly SO_2 mass emissions due to combustion of gaseous fuels for each day when gaseous fuels are combusted by the unit using the procedures in either section 2.3.1 or 2.3.2. The procedures in section 2.3.1 may be used for accounting for SO_2 mass emissions from any gaseous fuel with a total sulfur content ≤20.0 gr/100 scf. The procedures in section 2.3.2 may be used for pipeline natural gas or for any gaseous fuel for which the designated representative demonstrates to the satisfaction of the Administrator, in a petition to the Administrator under § 75.66(i), that the fuel has an SO_2 emission rate no greater than 0.0006 lb/mmBtu. Values used for calculations of SO_2 mass emission rates are summarized in Table D–6, below.

TABLE D–6.—GAS SAMPLING METHODS AND SULFUR AND HEAT CONTENT (GCV) VALUES USED IN CALCULATIONS

Parameter	Sampling technique/frequency	Value used in calculations
Gas Sulfur Content	Gaseous fuel in lots—as-delivered sampling [1]	Highest of all sampled values in previous calendar year OR maximum value allowed by contract [1]
	Any gaseous fuel—daily sampling [2]	Highest sulfur in previous 30 daily samples.
	Any gaseous fuel—continuous sampling (at least hourly) with a gas chromatograph.	Actual measured hourly average sulfur content.
Gas GCV/heat content	Gaseous fuel in lots—as-delivered sampling [1]	Highest of all sampled values in previous calendar year OR maximum value allowed by contract.[1]
	Gaseous fuels other than pipeline natural gas that are sampled for sulfur content—daily sampling.	Highest GCV in previous 30 daily samples.
	Gaseous fuels other than pipeline natural gas that are sampled for sulfur content—continuous sampling (at least hourly).	Actual measured hourly average GCV or highest GCV in previous 30 unit operating days.
	Pipeline natural gas—monthly sampling for GCV only.	Actual measured GCV OR highest of all sampled values in previous calendar year OR maximum value allowed by contract.[3]

[1] Assumed sulfur and GCV values may only continue to be used if sulfur content and gross calorific value of each as-delivered sample is no greater than the assumed value used to calculate emissions or heat input.

[2] Continuous sampling (at least hourly) may be required if the sulfur content exhibits too much variability (see section 2.3.3.4, below).
[3] Assumed GCV values of the highest sampled value in the previous calendar year or the maximum value allowed by contract may only continue to be used if gross calorific value of each monthly sample is no greater than the assumed value used to calculate heat input.

2.3.1 For gaseous fuels received in shipments or lots, sample each shipment or lot of fuel. A fuel lot for gaseous fuel is the volume of product gas from one source (supplier or pretreatment facility), intended as one shipment or delivery, which meets the fuel purchase specifications for sulfur content and GCV. For gaseous fuels, other than pipeline natural gas, that are not delivered in discrete lots or shipments, sample the gaseous fuel at least daily. Continuous sampling (at least hourly) with a gas chromatograph may be required if the sulfur content exhibits too much variability (see section 2.3.3.4, below). For gaseous fuel meeting the definition of pipeline natural gas in § 72.2 of this chapter, either use the procedures of section 2.3.2 of this appendix or sample the gaseous fuel at least daily. Sampling may be performed by either the owner or operator or by the fuel supplier.

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2.3.1.3 Determine the heat content or gross calorific value for a sample using the procedures of section 5.5 of appendix F to this part to determine the heat input rate for each hour the unit combusted gaseous fuel. Calculate heat input using the appropriate GCV from sections 2.3.1.4.1 through 2.3.1.4.3 of this appendix.

2.3.1.4 Calculate the hourly SO_2 mass emission rate, in lb/hr, using Equation D–4 of this appendix. Multiply the hourly metered volumetric flow rate of gas combusted (in 100 scfh) by the appropriate sulfur content from sections 2.3.1.4.1 through 2.3.1.4.2 of this appendix.

2.3.1.4.1 For gaseous fuels received in shipments or lots, use one of the following values: (1) the highest sulfur content and GCV from all shipments in the previous calendar year or (2) the maximum sulfur content and maximum GCV values established by agreement with the fuel supplier through a contract. Continue to use this assumed value until and unless the actual sampled sulfur content or gross calorific value of a delivery exceeds the previously reported assumed value.

If the actual sampled sulfur content or gross calorific value of a gas sample is greater than the assumed value for that parameter, then use the actual sampled value for sulfur content or gross calorific value of gas to calculate SO_2 mass emission rate or heat input rate as the new assumed sulfur content or gross calorific value. Continue to use this sampled value to calculate SO_2 mass emission rate or heat input rate until: (1) it is superseded by a new, higher value from a gas sample; (2) a new contract with a higher maximum sulfur content or gross calorific value is adopted, in which case the new contract value becomes the new assumed value; or (3) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

2.3.1.4.2 For gaseous fuels other than pipeline natural gas that are not received in shipments or lots that are transmitted by pipeline and sampled daily, use the highest sulfur content and GCV from the previous 30 daily gas samples. When continuous gas sampling (at least hourly) is required, use the actual measured hourly average sulfur content for each hour that the gaseous fuel is combusted.

2.3.1.4.3 For pipeline natural gas, use the highest sulfur content in the previous 30 daily gas samples, and the GCV from: (1) one or more samples taken during the most recent month when the unit burned gas for at least 48 hours; (2) the highest GCV from all samples in the previous calendar year; or (3) the maximum GCV values established by agreement with the fuel supplier through a contract. Continue to use this assumed value unless and until the actual sampled sulfur content or gross calorific value of a delivery exceeds the previously reported assumed value.

If the actual sampled sulfur content or gross calorific value of a gas sample is greater than the assumed value for that parameter, use the actual sampled value for sulfur content or gross calorific value of gas to calculate SO_2 mass emission rate or heat input rate as the new assumed sulfur content or gross calorific value. Continue to use this sampled value to calculate SO_2 mass emission rate or heat input rate until: (1) it is superseded by a new, higher value from a gas sample; (2) a new contract with a higher maximum sulfur content or gross calorific value is adopted, in which case the new contract value becomes the new assumed value; or (3) both the calendar year in which the sampled value exceeded the assumed value and the subsequent calendar year have elapsed.

2.3.2 If the fuel is pipeline natural gas, as defined in § 72.2 of this chapter, calculate SO_2 emissions under this section using a default SO_2 emission rate of 0.0006 lb/mmBtu.

2.3.2.1 Use the default SO_2 emission rate of 0.0006 lb/mmBtu and the hourly heat input rate from pipeline natural gas in mmBtu/hr, as determined using the procedures in section 5.5 of appendix F to this part. Calculate SO_2 mass emission rate using Equation D–5 of this appendix. Determine the heat content or gross calorific value for at least one sample each month that the gaseous fuel is combusted using the procedures in section 5.5 of appendix F to this part.

2.3.2.2 The procedures in this section 2.3.2 may also be used for a gaseous fuel other than pipeline natural gas if the Administrator approves a petition under § 75.66(i) in which the designated representative demonstrates that the gaseous fuel combusted at the unit has an SO_2 emission rate no greater than 0.0006 lb/mmBtu. To demonstrate this, the petition shall include at least 720 hours of fuel sampling data, indicating the total sulfur content and GCV of the fuel for each hour. Each hourly value of the total sulfur content in the gas or blend (in gr/100 scf) shall be converted to a ''fuel sulfur-to-heating value ratio,'' by dividing the total sulfur content by the gross calorific value of the fuel (in Btu/100 scf) and then multiplying by a conversion factor of 10^6 Btu/mmBtu. The mean value of the fuel sulfur-to-heating value ratios shall then be calculated. If the mean value of the ratios does not exceed 2.0 grains of sulfur per mmBtu, then the default SO_2 emission rate of 0.0006 lb/mmBtu may be used to account for SO_2 mass emissions under this part, whenever the gaseous fuel is combusted.

2.3.3 For all types of gaseous fuels, the owner or operator shall provide, in the monitoring plan for the unit, historical fuel sampling information on the sulfur content of the gaseous fuel sufficient to demonstrate that use of this appendix is applicable because the gas has a total sulfur content of 20.0 grain/100 scf or less. Provide this information with the initial monitoring plan for the unit and following any significant changes in gas contract or source of supply. However, for units combusting pipeline natural gas that have gas flowmeters certified prior to the effective date of this rule, this information may be retained on site in a form suitable for inspection, rather than submitted as an update to the monitoring plan. In addition, provide the following specific information in the monitoring plan required under § 75.53, depending on the type of gaseous fuel:

2.3.3.1 For pipeline natural gas, provide information demonstrating that the definition of pipeline natural gas in § 72.2 of this chapter has been met. This demonstration must be made using one of the following sources of information: (1) the gas quality characteristics specified by a purchase contract or by a pipeline transportation contract; (2) a certification of the gas vendor, based on routine vendor sampling and analysis; or (3) at least one year's worth of analytical data on the fuel hydrogen sulfide content from samples taken monthly or more frequently.

2.3.3.2 For gaseous fuel other than pipeline natural gas for which a petition has been submitted and approved under section 2.3.2.2 of this appendix, provide the information required to be included in the petition pursuant to section 2.3.2.2.

2.3.3.3 For liquefied petroleum gas and other gaseous fuels provided in batches or lots having uniform sulfur content, provide either contractual information from the fuel supplier or provide historical information on each lot of liquefied petroleum gas from at least one year.

2.3.3.4 For any other gaseous fuel or blend, including gas produced by a variable process (e.g., digester gas or landfill gas), provide data on the fuel sulfur content, as follows. Provide a minimum of 720 hours of data, indicating the total sulfur content of the gas or blend (in gr/100 scf). The data shall be obtained with a gas chromatograph, and, for gaseous fuel produced by a variable process, the data shall be representative of all process operating conditions. The data shall be reduced to hourly averages and shall be

used to determine whether daily sampling of the sulfur content of the gas or blend is sufficient or whether sampling, at least hourly, with a gas chromatograph is required. Specifically, daily gas sampling shall be sufficient, provided that either: (1) the mean value of the total sulfur content of the gas or blend is ≤7 grains per 100 scf; or (2) the standard deviation of the hourly average values from the mean does not exceed 5 grains per 100 scf. If the gas or blend does not meet requirement (1) or (2), then sampling, at least hourly, of the fuel with a gas chromatograph (GCH) and hourly reporting of the hourly average sulfur content of the fuel is required. If sampling, at least hourly, from a gas chromatograph is required, the owner or operator shall develop and implement a program to quality assure the data from the GCH, in accordance with the manufacturer's recommended procedures. The quality assurance procedures shall be kept on-site, in a form suitable for inspection.

2.4 * * *

2.4.1 Missing Data for Oil and Gas Samples

When oil sulfur content, density, or gross calorific value data are missing or invalid for an oil or gas sample taken according to the procedures in section 2.2.3, 2.2.4.1, 2.2.4.2, 2.2.4.3, 2.3.1, 2.3.1.1, 2.3.1.2, or 2.3.1.3 of this appendix, then substitute the maximum potential sulfur content, density, or gross calorific value of that fuel from Table D–7 of this appendix.

TABLE D–7.—MISSING DATA SUBSTITUTION PROCEDURES FOR SULFUR, DENSITY, AND GROSS CALORIFIC VALUE

Data	
Parameter	Missing data substitution maximum potential value
Oil Sulfur Content	3.5 percent for residual oil, or. 1.0 percent for diesel fuel.
Oil Density	8.5 lb/gal for residual oil, or 7.4 lb/gal for diesel fuel.
Oil GCV	19,500 Btu/lb for residual oil, or 20,000 Btu/lb for diesel fuel.
Gas Sulfur Content	0.30 gr/100 scf for pipeline natural gas, or 20.0 gr/100 scf for other gaseous fuel.
Gas GCV/Heat Content	1100 Btu/scf for pipeline natural gas, or 2100 Btu/scf for other gaseous fuel.

2.4.2 Whenever data are missing from any fuel flowmeter that is part of an excepted monitoring system under appendix D or E to this part, where the fuel flowmeter data are required to determine the amount of fuel combusted by the unit, use the procedures in sections 2.4.2.2 and 2.4.2.3 of this appendix to account for the flow rate of fuel combusted at the unit for each hour during the missing data period. In addition, a fuel flowmeter used for measuring fuel combusted by a peaking unit may use the simplified fuel flow missing data procedure in section 2.4.2.1 of this appendix.

2.4.2.1 Simplified Fuel Flow Missing Data for Peaking Units.

If no fuel flow rate data are available for a fuel flowmeter system installed on a peaking unit (as defined in § 72.2 of this chapter), then substitute for each hour of missing data using the maximum potential fuel flow rate. The maximum potential fuel flow rate is the lesser of the following: (1) the maximum fuel flow rate the unit is capable of combusting or (2) the maximum flow rate that the flowmeter can measure (i.e, upper range value of flowmeter leading to a unit).

2.4.2.2 * * *

2.4.2.3 For hours where two or more fuels are combusted, substitute the maximum hourly fuel flow rate measured and recorded by the flowmeter (or flowmeters, where fuel is recirculated) for the fuel for which data are missing at the corresponding load range recorded for each missing hour during the previous 720 hours when the unit combusted that fuel with any other fuel. For hours where no previous recorded fuel flow rate data are available for that fuel during the missing data period, calculate and substitute the maximum potential flow rate of that fuel for the unit as defined in section 2.4.2.2 of this appendix.

2.4.3 * * *

65. Section 3 of appendix D to part 75 is amended by:

a. Revising sections 3, 3.1, 3.2, 3.2.1, 3.2.3, 3.2.4, and 3.3;

b. Redesignating section 3.4 as section 3.5 and revising the introductory text; and

c. Adding a new section 3.4, to read as follows:

3. Calculations

Use the calculation procedures in section 3.1 of this appendix to calculate SO_2 mass emission rate. Where an oil flowmeter records volumetric flow rate, use the calculation procedures in section 3.2 of this appendix to calculate the mass flow rate of oil. Calculate hourly SO_2 mass emission rate from gaseous fuel using the procedures in section 3.3 of this appendix. Calculate hourly heat input rate for oil and for gaseous fuel using the equations in section 5.5 of appendix F to this part. Calculate total SO_2 mass emissions and heat input as provided under section 3.4 of this appendix.

3.1 SO_2 Mass Emission Rate Calculation for Oil

3.1.1 Use the following equation to calculate SO_2 mass emissions per hour (lb/hr):

$$M_{SO_2} = 2.0 \times M_{oil} \times \frac{\%S_{oil}}{100.0}$$

(Eq. D–2)

where:

MSO_2 = Hourly mass emission rate of SO_2 emitted from combustion of oil, lb/hr.

M_{oil} = Mass rate of oil consumed per hr, lb/hr.

$\%S_{oil}$ = Percentage of sulfur by weight measured in the sample.

2.0 = Ratio of lb SO_2/lb S.

3.1.2 Record the SO_2 mass emission rate from oil for each hour that oil is combusted.

3.2 Mass Flow Rate Calculation for Oil Using Volumetric Flow Rate

3.2.1 Where the oil flowmeter records volumetric flow rate rather than mass flow rate, calculate and record the oil mass flow rate for each hourly period using hourly oil flow rate measurements and the density or specific gravity of the oil sample.

* * * * *

3.2.3 Where density of the oil is determined by the applicable ASTM procedures from section 2.2.5 of this appendix, use the following equation to calculate the rate of the mass of oil consumed (in lb/hr):

$M_{oil}=V_{oil}\times D_{oil}$

(Eq. D–3)

Where:

M_{oil} = Mass rate of oil consumed per hr, lb/hr.

V_{oil} = Volume rate of oil consumed per hr, measured in scf, gal, barrels, or m^3.

D_{oil} = Density of oil, measured in lb/scf, lb/gal, lb/barrel, or lb/m^3.

3.2.4 Calculate the hourly heat input rate to the unit from oil (mmBtu/hr) by multiplying the heat content of the daily oil sample by the hourly oil mass rate.

3.3 SO_2 Mass Emissions Rate Calculation for Gaseous Fuels

3.3.1 Use the following equation to calculate the SO_2 emission rate using the gas sampling and analysis procedures in section 2.3.1 of this appendix:

$$M_{(SO_2)g} = \left(\frac{2.0}{7000}\right) \times Q_g \times S_g$$

(Eq. D–4)

Where:

$M_{(SO2)g}$ = Hourly mass rate of SO_2 emitted due to combustion of gaseous fuel, lb/hr.

Q_g = Hourly metered flow rate of gaseous fuel combusted, 100 scf/hr.

S_g = Sulfur content of gaseous fuel, in grain/100 scf.

2.0 = Ratio of lb SO_2/lb S.

7000 = Conversion of grains/100 scf to lb/100 scf.

3.3.2 Use the following equation to calculate the SO_2 emission rate using the

0.0006 lb/mmBtu emission rate in section 2.3.2 of this appendix:

$M_{(SO2)g} = ER \times HI_g$

(Eq. D–5)

Where:

$M_{(SO2)g}$ = Hourly mass rate of SO_2 emissions from combustion of pipeline natural gas, lb/hr.

ER = SO_2 emission rate of 0.0006 lb/mmBtu for pipeline natural gas.

Hi_g = Hourly heat input rate of pipeline natural gas, calculated using procedures in appendix F to this part, in mmBtu/hr.

3.3.3 Record the SO_2 mass emission rate for each hour when the unit combusts gaseous fuel.

3.4 Conversion of Rates to Totals and Summation of Quarterly and Cumulative Values

3.4.1 SO_2 Mass Emissions Conversions and Summations.

For a unit or for a common pipe, calculate total quarterly SO_2 mass emissions (using Equation D–6) and total cumulative SO_2 mass emissions (using Equation D–7). First convert hourly SO_2 mass emission rates for each fuel to total hourly SO_2 mass emissions, by multiplying the hourly rates by the fuel usage time. Second, sum the total hourly SO_2 mass emissions from all fuels for the quarter. Third, convert the quarterly SO_2 mass emission total to tons. Finally, for cumulative emissions, sum the quarterly SO_2 mass emission totals, in tons, for each quarter in the year to date.

$$SO_{2_q} = \frac{1}{2000} \sum_{\text{first fuel}}^{\text{last fuel}} \sum_{\text{hour}=1}^{n} \sum_{\text{first system}}^{\text{last system}} SO_{2i\ \text{fuel system}} t_i$$

(Eq. D–6)

Where:

SO_{2q} = Total SO_2 mass emissions for the quarter, tons.

$SO_{2i\ fuel\ system}$ = SO_2 mass emission rate for a given fuel for a particular fuel flow system, lb/hr.

t_i = Fuel usage time for the fuel and system, hour or fraction of an hour.

$$SO_{2_c} = \sum_{q=1}^{\text{the current quarter}} SO_{2_q}$$

(Eq. D–7)

Where:

SO_{2c} = Total SO_2 mass emissions for the year to date, tons.

SO_{2q} = Total SO_2 mass emissions for the quarter, tons.

3.4.2 Heat Input Conversions and Summations

Calculate total quarterly (using Equation D–8) and total cumulative (using Equation D–9) heat input for a unit or common pipe with fuel flow systems.

$$HI_q = \sum_{\text{first fuel}}^{\text{last fuel}} \sum_{\text{hour}=1}^{n} \sum_{\text{first system}}^{\text{last system}} HI_{i\ \text{fuel system}} t_i$$

(Eq. D–8)

Where:

HI_q = Total heat input for the quarter, mmBtu.

$HI_{i\ fuel\ system}$ = Heat input rate during fuel usage for a given fuel for a particular fuel flow system, using Equation F–19 or F–20, mmBtu/hr.

t_i = Fuel usage time for the fuel and system, hour or fraction of an hour.

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q$$

(Eq. D–9)

Where:

HI_c=Total heat input for the year to date, mmBtu.

HI_q=Total heat input for the quarter, mmBtu.

3.5 Records and Reports

Calculate and record quarterly and cumulative SO_2 mass emissions and heat input for each calendar quarter using the procedures and equations of section 3.4 of this appendix.

* * * * *

APPENDIX E TO PART 75—OPTIONAL NO_X EMISSIONS ESTIMATION PROTOCOL FOR GAS-FIRED PEAKING UNITS AND OIL-FIRED PEAKING UNITS

* * * * *

66. Section 2 of appendix E to part 75 is amended by revising sections 2.5.4 and 2.5.5 to read as follows:

2. Procedure

* * * * *

2.5 Missing Data Procedures

* * * * *

2.5.4 Substitute missing data from a fuel flowmeter using the procedures in section 2.4.2 of appendix D to this part.

2.5.5 Substitute missing data for gross calorific value of fuel using the procedures in sections 2.4.1 of appendix D to this part.

67. Section 3 of Appendix E to part 75 is amended by revising sections 3.1, 3.3.1, and 3.3.4 to read as follows:

3. Calculations

3.1 Heat Input

Calculate the total heat input by summing the product of heat input rate and fuel usage time of each fuel, as in the following equation:

$H_T = HI_{fuel\ 1}t_1 + HI_{fuel\ 2}t_2 + HI_{fuel\ 3}t_3 + \ldots + HI_{lastfuel}t_{last}$

(Eq. E–1)

Where:

H_T=Total heat input of fuel flow or a combination of fuel flows to a unit, mmBtu.

$HI_{fuel\ 1,2,3,...last}$=Heat input rate from each fuel, in mmBtu/hr as determined using Equation F–19 or F–20 in section 5.5 of appendix F to this part, mmBtu/hr.

$t_{1,2,3....last}$=Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)).

* * * * *

3.3 * * *

3.3.1 Conversion from Concentration to Emission Rate.

Convert the NO_X concentrations (ppm) and O_2 concentrations to NO_X emission rates (to the nearest 0.01 lb/mmBtu for tests performed prior to January 1, 2000 or to the nearest 0.001 lb/mmBtu for tests performed on and after January 1, 2000), according to the appropriate one of the following equations: F–5 in appendix F to this part for dry basis concentration measurements or 19–3 in Method 19 of appendix A to part 60 of this chapter for wet basis concentration measurements.

* * * * *

3.3.4 Average NO_X Emission Rate During Co-firing of Fuels.

$$E_h = \frac{\sum_{f=1}^{\text{all fuels}} \left(E_f \times HI_f t_f\right)}{H_T}$$

(Eq. E–2)

Where:

E_h=NO_X emission rate for the unit for the hour, lb/mmBtu.

E_f=NO_X emission rate for the unit for a given fuel at heat input rate HI_f, lb/mmBtu.

HI_f=Heat input rate for the hour for a given fuel, during the fuel usage time, as determined using Equation F–19 or F–20 in section 5.5 of appendix F to this part, mmBtu/hr

H_T=Total heat input for all fuels for the hour from Equation E–1.

t_f=Fuel usage time for each fuel (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)).

Note: For hours where a fuel is combusted for only part of the hour, use the fuel flow rate or mass flow rate during the fuel usage time, instead of the total fuel flow or mass flow during the hour, when calculating heat input rate using Equation F–19 or F–20.

68. Section 2 of appendix F to part 75 is revised to read as follows:

Appendix F to Part 75—Conversion Procedures

* * * * *

2. Procedures for SO_2 Emissions

Use the following procedures to compute hourly SO_2 mass emission rate (in lb/hr) and quarterly and annual SO_2 total mass emissions (in tons). Use the procedures in Method 19 in appendix A to part 60 of this chapter to compute hourly SO_2 emission rates (in lb/mmBtu) for qualifying Phase I technologies. When computing hourly SO_2 emission rate in lb/mmBtu, a minimum concentration of 5.0 percent CO_2 and a maximum concentration of 14.0 percent O_2 may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO_2 is less than 5.0 percent CO_2 or the hourly average concentration of O_2 is greater than 14.0 percent O_2.

2.1 When measurements of SO_2 concentration and flow rate are on a wet basis, use the following equation to compute hourly SO_2 mass emission rate (in lb/hr):

$E_h = KC_hQ_h$

(Eq. F–1)

Where:

E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.

K = 1.660×10^{-7} for SO_2, (lb/scf)/ppm.

C_h = Hourly average SO_2 concentration during unit operation, stack moisture basis, ppm.

Q_h = Hourly average volumetric flow rate during unit operation, stack moisture basis, scfh.

2.2 When measurements by the SO_2 pollutant concentration monitor are on a dry basis and the flow rate monitor measurements are on a wet basis, use the following equation to compute hourly SO_2 mass emission rate (in lb/hr):

$$E_h = KC_{hp}Q_{hs}\frac{\left(100 - \%H_2O\right)}{100}$$

(Eq. F–2)

Where:

E_h = Hourly SO_2 mass emission rate during unit operation, lb/hr.

K = $1.660 \times 10_{-7}$ for SO_2, (lb/scf)/ppm.

C_{hp} = Hourly average SO_2 concentration during unit operation, ppm (dry).

Q_{hs}= Hourly average volumetric flow rate during unit operation, scfh as measured (wet).

$\%H_2O$ = Hourly average stack moisture content during unit operation, percent by volume.

2.3 Use the following equations to calculate total SO_2 mass emissions for each calendar quarter (Equation F–3) and for each calendar year (Equation F–4), in tons:

$$E_q = \frac{\sum_{h=i}^{n} E_h t_h}{2000}$$

(Eq. F–3)

Where:

E_q = Quarterly total SO_2 mass emissions, tons.

E_h = Hourly SO_2 mass emission rate, lb/hr.

t_h = Unit operating time, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n = Number of hourly SO_2 emissions values during calendar quarter.

2000 = Conversion of 2000 lb per ton.

$$E_a = \sum_{q=1}^{4} E_q$$

(Eq. F–4)

Where:

E_a = Annual total SO_2 mass emissions, tons.

E_q = Quarterly total SO_2 mass emissions, tons.

q = Quarters for which E_q are available during calendar year.

2.4 Round all SO_2 mass emission rates and totals to the nearest tenth.

69. Section 3 of appendix F to part 75 is amended by revising sections 3.3.2, 3.3.3, 3.3.4, 3.4, and 3.5 to read as follows:

3. Procedures for NO_X Emission Rate

* * * * *

3.3 * * *

3.3.2 E = Pollutant emissions during unit operation, lb/mmBtu.

3.3.3 C_h = Hourly average pollutant concentration during unit operation, ppm.

3.3.4 $\%O_2$, $\%CO_2$ = Oxygen or carbon dioxide volume during unit operation (expressed as percent O_2 or CO_2). A minimum concentration of 5.0 percent CO_2 and a maximum concentration of 14.0 percent O_2 may be substituted for measured diluent gas concentration values at boilers during hours when the hourly average concentration of CO_2 is <5.0 percent CO_2 or the hourly average concentration of O_2 is >14.0 percent O_2. A minimum concentration of 1.0 percent CO_2 and a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values at stationary gas turbines during hours when the hourly average concentration of CO_2 is <1.0 percent CO_2 or the hourly average concentration of O_2 is >19.0 percent O_2.

* * * * *

3.4 Use the following equations to calculate the average NO_X emission rate for each calendar quarter (Equation F–9) and the average emission rate for the calendar year (Equation F–10), in lb/mmBtu:

$$E_q = \sum_{i=1}^{n} \frac{E_i}{n}$$

(Eq. F–9)

Where:

E_q = Quarterly average NO_X emission rate, lb/mmBtu.

E_i = Hourly average NO_X emission rate during unit operation, lb/mmBtu.

n = Number of hourly rates during calendar quarter.

$$E_a = \sum_{i=1}^{m} \frac{E_i}{m}$$

(Eq. F–10)

Where:

E_a = Average NO_X emission rate for the calendar year, lb/mmBtu.

E_i = Hourly average NO_X emission rate during unit operation, lb/mmBtu.
m = Number of hourly rates for which E_i is available in the calendar year.

3.5 Round all NO_X emission rates to the nearest 0.01 lb/mmBtu prior to January 1, 2000 and to the nearest 0.001 lb/mmBtu on and after January 1, 2000.

70. Section 4 of appendix F to part 75 is amended by revising sections 4.1, 4.2, 4.3, and 4.4.1 to read as follows:

4. Procedures for CO_2 Mass Emissions

* * * * *

4.1 When CO_2 concentration is measured on a wet basis, use the following equation to calculate hourly CO_2 mass emissions rates (in tons/hr):

$E_h = KC_hQ_h$

(Eq. F–11)

Where:

E_h = Hourly CO_2 mass emission rate during unit operation, tons/hr.
K = 5.7 X 10^{-7} for CO_2, (tons/scf) /%CO_2.
C_h = Hourly average CO_2 concentration during unit operation, wet basis, percent CO_2. For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2, provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2, provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of heat input for that hour.
Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

4.2 When CO_2 concentration is measured on a dry basis, use Equation F–2 to calculate the hourly CO_2 mass emission rate (in tons/hr) with a K-value of 5.7×10^{-7} (tons/scf) percent CO_2, where E_h = hourly CO_2 mass emission rate, tons/hr and C_{hp} = hourly average CO_2 concentration in flue, dry basis, percent CO_2.

4.3 Use the following equations to calculate total CO_2 mass emissions for each calendar quarter (Equation F–12) and for each calendar year (Equation F–13):

$$E_{CO_2q} = \sum_{h=1}^{H_R} E_h t_h$$

(Eq. F–12)

Where:

$E_{(CO2)q}$ = Quarterly total CO_2 mass emissions, tons.
E_h = Hourly CO_2 mass emission rate, tons/hr.
t_h = Unit operating time, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).
H_R = Number of hourly CO_2 mass emission rates available during calendar quarter.

* * * * *

4.4 * * *

4.4.1 Use appropriate F and F_c factors from section 3.3.5 of this appendix in the following equation to determine hourly average CO_2 concentration of flue gases (in percent by volume):

$$CO_{2d} = 100 \frac{F_c}{F} \frac{20.9 - O_{2d}}{20.9}$$

(Eq. F–14a)

Where:

CO_{2d} = Hourly average CO_2 concentration during unit operation, percent by volume, dry basis.
F, F_c = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.
20.9 = Percentage of O_2 in ambient air.
O_{2d} = Hourly average O2 concentration during unit operation, percent by volume, dry basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2, provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2, provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of heat input for that hour.

$$CO_{2w} = \frac{100}{20.9} \frac{F_c}{F} \left[20.9 \left(\frac{100 - \%H_2O}{100} \right) - O_{2w} \right]$$

or

(Eq. F–14b)

Where:

CO_{2w} = Hourly average CO_2 concentration during unit operation, percent by volume, wet basis.
O_{2w} = Hourly average O_2 concentration during unit operation, percent by volume, wet basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2, provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of heat input for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2, provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of heat input for that hour.
F, F_c = F-factor or carbon-based F_c-factor from section 3.3.5 of this appendix.
20.9 = Percentage of O_2 in ambient air.
%H_2O = Moisture content of gas in the stack, percent.

* * * * *

71. Section 5 of appendix F to part 75 is amended by revising sections 5, 5.1, 5.2, 5.5, 5.5.1, and 5.5.2 and by adding new sections 5.3, 5.6, and 5.7 to read as follows:

5. Procedures for Heat Input

Use the following procedures to compute heat input rate to an affected unit (in mmBtu/hr or mmBtu/day):

5.1 Calculate and record heat input rate to an affected unit on an hourly basis, except as provided below. The owner or operator may choose to use the provisions specified in § 75.16(e) or in section 2.1.2 of appendix D to this part in conjunction with the procedures provided below to apportion heat input among each unit using the common stack or common pipe header.

5.2 For an affected unit that has a flow monitor (or approved alternate monitoring system under subpart E of this part for measuring volumetric flow rate) and a diluent gas (O_2 or CO_2) monitor, use the recorded data from these monitors and one of the following equations to calculate hourly heat input rate (in mmBtu/hr).

5.2.1 When measurements of CO_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F_c} \frac{\%CO_{2w}}{100}$$

(Eq. F–15)

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-factor, listed in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2w}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 wet basis. For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2, provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2, provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour.

5.2.2 When measurements of CO_2 concentration are on a dry basis, use the following equation:

$$HI = Q_h \left[\frac{(100 - \%H_2O)}{100 F_c} \right] \left(\frac{\%CO_2d}{100} \right)$$

(Eq. F–16)

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_h = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F_c = Carbon-based F-Factor, listed above in section 3.3.5 of this appendix for each fuel, scf/mmBtu.

$\%CO_{2d}$ = Hourly concentration of CO_2 during unit operation, percent CO_2 dry basis. For boilers, a minimum concentration of 5.0 percent CO_2 may be substituted for the measured concentration when the hourly average concentration of CO_2 is < 5.0 percent CO_2, provided that this minimum concentration of 5.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a minimum concentration of 1.0 percent CO_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of CO_2 is < 1.0 percent CO_2, provided that this minimum concentration of 1.0 percent CO_2 is also used in the calculation of CO_2 mass emissions for that hour.

$\%H_2O$ = Moisture content of gas in the stack, percent.

5.2.3 When measurements of O_2 concentration are on a wet basis, use the following equation:

$$HI = Q_w \frac{1}{F} \frac{\left[(20.9/100)(100 - \%H_2O) - \%O_2w \right]}{20.9}$$

(Eq. F–17)

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Q_w = Hourly average volumetric flow rate during unit operation, wet basis, scfh.

F = Dry basis F-Factor, listed above in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

$\%O_{2w}$ = Hourly concentration of O_2 during unit operation, percent O_2 wet basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2, provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2, provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour.

$\%H_2O$ = Hourly average stack moisture content, percent by volume.

5.2.4 When measurements of O_2 concentration are on a dry basis, use the following equation:

$$HI = Q_w \left[\frac{(100 - \%H_2O)}{100\ F} \right] \left[\frac{(20.9 - \%O_{2d})}{20.9} \right]$$

(Eq. F–18)

Where:

HI = Hourly heat input rate during unit operation, mmBtu/hr.

Qw = Hourly average volumetric flow during unit operation, wet basis, scfh.

F = Dry basis F-factor, listed above in section 3.3.5 of this appendix for each fuel, dscf/mmBtu.

$\%H_2O$ = Moisture content of the stack gas, percent.

$\%O_{2d}$ = Hourly concentration of O_2 during unit operation, percent O_2 dry basis. For boilers, a maximum concentration of 14.0 percent O_2 may be substituted for the measured concentration when the hourly average concentration of O_2 is > 14.0 percent O_2, provided that this maximum concentration of 14.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour.. For stationary gas turbines, a maximum concentration of 19.0 percent O_2 may be substituted for measured diluent gas concentration values during hours when the hourly average concentration of O_2 is > 19.0 percent O_2, provided that this maximum concentration of 19.0 percent O_2 is also used in the calculation of CO_2 mass emissions for that hour.

5.3 Heat Input Summation (for Heat Input Determined Using a Flow Monitor and Diluent Monitor)

5.3.1 Calculate total quarterly heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_q = \sum_{hour=1}^{n} HI_i t_i$$

(Eq. F–18a)

Where:

HI_q = Total heat input for the quarter, mmBtu.

HI_i = Hourly heat input rate during unit operation, using Equation F–15, F–16, F–17, or F–18, mmBtu/hr.

t_i = Hourly operating time for the unit or common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

5.3.2 Calculate total cumulative heat input for a unit or common stack using a flow monitor and diluent monitor to calculate heat input, using the following equation:

$$HI_c = \sum_{q=1}^{\text{the current quarter}} HI_q$$

(Eq. F–18b)

Where:

HI_c = Total heat input for the year to date, mmBtu.

HI_q = Total heat input for the quarter, mmBtu.

5.4 [Reserved]

5.5 For a gas-fired or oil-fired unit that does not have a flow monitor and is using the procedures specified in appendix D to this part to monitor SO_2 emissions or for any unit using a common stack for which the owner or operator chooses to determine heat input by fuel sampling and analysis, use the following procedures to calculate hourly heat input rate in mmBtu/hr. The procedures of section 5.5.3 of this appendix shall not be used to determine heat input from a coal unit that is required to comply with the provisions of this part for monitoring, recording, and reporting NO_X mass emissions under a state or federal NO_X mass emission reduction program.

5.5.1 When the unit is combusting oil, use the following equation to calculate hourly heat input rate:

$$HI_o = M_o \frac{GCV_o}{10^6}$$

(Eq. F–19)

Where:

HI_o = Hourly heat input rate from oil, mmBtu/hr.

M_o = Mass rate of oil consumed per hour, as determined using procedures in appendix D to this part, in lb/hr, tons/hr, or kg/hr.

GCV_o = Gross calorific value of oil, as measured by ASTM D240–87 (Reapproved 1991), ASTM D2015–91, or ASTM D2382–88 for each oil sample under section 2.2 of appendix D to this part, Btu/unit mass (incorporated by reference under § 75.6).

10_6 = Conversion of Btu to mmBtu. When performing oil sampling and analysis solely for the purpose of the missing data procedures in § 75.36, oil samples for measuring GCV may be taken weekly, and the procedures specified in appendix D to this part for determining the mass rate of oil consumed per hour are optional.

5.5.2 When the unit is combusting gaseous fuels, use the following equation to calculate heat input rate from gaseous fuels for each hour:

$$HI_g = \frac{\left(Q_g \times GCV_g\right)}{10^6}$$

(Eq. F–20)

Where:

HI_g=Hourly heat input rate from gaseous fuel, mmBtu/hour.

Q_g=Metered flow rate of gaseous fuel combusted during unit operation, hundred cubic feet.

GCV_g=Gross calorific value of gaseous fuel, as determined by sampling (for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, for each hourly average for gas measured hourly with a GCH, or for each monthly sample of pipeline natural gas, or as verified by the contractual supplier at least once every month pipeline natural gas is combusted, as specified in section 2.3 of appendix D to this part) using ASTM D1826–88, ASTM D3588–91, ASTM D4891–89, GPA Standard 2172–86 ''Calculation of Gross Heating Value, Relative Density and Compressibility Factor for Natural Gas Mixtures from Compositional Analysis,'' or GPA Standard 2261-90 ''Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography,'' Btu/100 scf (incorporated by reference under § 75.6).

10^6=Conversion of Btu to mmBtu.

* * * * *

5.6 Heat Input Rate Apportionment for Units Sharing a Common Stack or Pipe

5.6.1 Where applicable, the owner or operator of an affected unit that determines heat input rate at the unit level by apportioning the heat input monitored at a common stack or common pipe using megawatts should apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{MW_i t_i}{\sum_{i=1}^{n} MW_i t_i}\right]$$

(Eq. F–21a)

Where:

HI_i=Heat input rate for a unit, mmBtu/hr.

HI_{CS}=Heat input rate at the common stack or pipe; mmBtu/hr.

MW_i=Gross electrical output, MWe.

t_i=Operating time at a particular unit, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS}=Operating time at common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n=Total number of units using the common stack.

i=Designation of a particular unit.

5.6.2 Where applicable, the owner or operator of an affected unit that determines the heat input rate at the unit level by apportioning the heat input rate monitored at a common stack or common pipe using steam load should apportion the heat input rate using the following equation:

$$HI_i = HI_{CS}\left(\frac{t_{CS}}{t_i}\right)\left[\frac{SF_i t_i}{\sum_{i=1}^{n} SF_i t_i}\right]$$

(Eq. F–21b)

Where:

HI_i=Heat input rate for a unit, mmBtu/hr.

HI_{CS}=Heat input rate at the common stack or pipe, mmBtu/hr.

SF=Gross steam load, lb/hr.

t_i=Operating time at a particular unit, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_{CS}=Operating time at common stack, hour or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

n=Total number of units using the common stack.

i=Designation of a particular unit.

5.7 Heat Input Rate Summation for Units with Multiple Stacks or Pipes

The owner or operator of an affected unit that determines the heat input rate at the unit level by summing the heat input rates monitored at multiple stacks or multiple pipes should sum the heat input rates using the following equation:

$$HI_{Unit} = \frac{\sum_{s=1}^{n} HI_s t_s}{t_{Unit}}$$

(Eq. F–21c)

Where:

HI_{Unit}=Heat input rate for a unit, mmBtu/hr.

HI_s=Heat input rate for each stack or duct leading from the unit, mmBtu/hr.

t_{Unit}=Operating time for the unit, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

t_s=Operating time during which the unit is exhausting through the stack or duct, hour or fraction of the hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator).

72. Section 8 of appendix F to part 75 is added to read as follows:

8. Procedures for NO_X Mass Emissions

The owner or operator of a unit that is required to monitor, record, and report NO_X mass emissions under a state or federal NO_X mass emission reduction program must use the procedures in section 8.1 to account for hourly NO_X mass emissions, and the procedures in section 8.2 to account for quarterly, seasonal, and annual NO_X mass emissions if the provisions of subpart H of this part are adopted as requirements under such a program.

8.1 Use the following procedures to calculate hourly NO_X mass emissions in lbs for the hour.

8.1.1 If both NO_X emission rate and heat input are monitored at the same unit or stack level (e.g, the NO_X emission rate value and heat input value both represent all of the units exhausting to the common stack), use the following equation:

$$M_{NO_{X_h}} = E_h HI_h t_h$$

(Eq. F–23)

Where:

$M_{NOx(h)}$=NO_X mass emissions in lbs for the hour.

E_h=Hourly average NO_X emission rate for hour h, lb/mmBtu.

H_{ih}=Hourly average heat input rate for hour h, mmBtu/hr.

t_h=Monitoring location operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). If the combined NO_X emission rate and heat input are monitored for all of the units in a common stack, the monitoring location operating time is equal to the total time when any of those units was exhausting through the common stack.

8.1.2 If NO_X emission rate is measured at a common stack and heat input is measured at the unit level, sum the hourly heat inputs at the unit level according to the following formula:

$$HI_{CS} = \frac{\sum_{u=1}^{p} HI_u t_u}{t_{CS}}$$

(Eq. F–24)

Where:

HI_{CS}=Hourly average heat input rate for hour h for the units at the common stack, mmBtu/hr.

t_{CS}=Common stack operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator)(e.g., total time when any of the units which exhaust through the common stack are operating).

HI_u=Hourly average heat input rate for hour h for the unit, mmBtu/hr.

t_u=Unit operating time for hour h, in hours or fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator). Use the hourly heat input rate at the common stack level and the hourly average NO_X emission rate at the common stack level and the procedures in section 8.1.1 of this appendix to determine the hourly NO_X mass emissions at the common stack.

8.1.3 If a unit has multiple ducts and NO_X emission rate is only measured at one duct, use the NO_X emission rate measured at the duct, the heat input measured for the unit, and the procedures in section 8.1.1 of this appendix to determine NO_X mass emissions.

8.1.4 If a unit has multiple ducts and NO_X emission rate is measured in each duct, heat input shall also be measured in each duct and the procedures in section 8.1.1 of this appendix shall be used to determine NO_X mass emissions.

8.2 Use the following procedures to calculate quarterly, cumulative ozone season, and cumulative yearly NO_X mass emissions, in tons:

$$M_{(NO_X)_{time\ period}} = \frac{\sum_{h=1}^{p} M_{(NO_X)_h}}{2000}$$

(Eq. F–25)

Where:

$M_{(NOX)time\ period}$=NO_X mass emissions in tons for the given time period (quarter, cumulative ozone season, cumulative year-to-date).

$M_{(NOX)h}$=NO_X mass emissions in lbs for the hour.

p=The number of hours in the given time period (quarter, cumulative ozone season, cumulative year-to-date).

8.3 Specific provisions for monitoring NO_X mass emissions from common stacks. The owner or operator of a unit utilizing a common stack may account for NO_X mass emissions using either of the following methodologies, if the provisions of subpart H are adopted as requirements of a state or federal NO_X mass reduction program:

8.3.1 The owner or operator may determine both NO_X emission rate and heat input at the common stack and use the procedures in section 8.1.1 of this appendix to determine hourly NO_X mass emissions.

8.3.2 The owner or operator may determine the NO_X emission rate at the common stack and the heat input at each of the units and use the procedures in section 8.1.2 of this appendix to determine the hourly NO_X mass emissions.

APPENDIX G TO PART 75—DETERMINATION OF CO_2 EMISSIONS

* * * * *

73. Section 2 of appendix G to part 75 is amended by revising the term ''Wc'' that follows Equation G–1 to read as follows:

2. Procedures for Estimating CO_2 Emissions From Combustion

2.1 * * *

(Eq. G–1)

Where:

* * * * *

W_C=Carbon burned, lb/day, determined using fuel sampling and analysis and fuel feed rates. Collect at least one fuel sample during each week that the unit combusts coal, one sample per each shipment for oil and diesel fuel, and one fuel sample for each delivery for gaseous fuel in lots, for each daily gas sample for gaseous fuel delivered by pipeline, or for each monthly sample of pipeline natural gas. Collect coal samples from a location in the fuel handling system that provides a sample representative of the fuel bunkered or consumed during the week. Determine the carbon content of each fuel sampling using one of the following methods: ASTM D3178–89 or ASTM D5373–93 for coal; ASTM D5291–92 ''Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants,'' ultimate analysis of oil, or computations based upon ASTM D3238–90 and either ASTM D2502–87 or ASTM D2503–82 (Reapproved 1987) for oil; and computations based on ASTM D1945–91 or ASTM D1946–90 for gas. Use daily fuel feed rates from company records for all fuels and the carbon content of the most recent fuel sample under this section to determine tons of carbon per day from combustion of each fuel. (All ASTM methods are incorporated by reference under § 75.6). Where more than one fuel is combusted during a calendar day, calculate total tons of carbon for the day from all fuels.

* * * * *

74. Appendix G to part 75 is amended by adding a new section 5 and Table G–1 to read as follows:

5. Missing Data Substitution Procedures for Fuel Analytical Data

Use the following procedures to substitute for missing fuel analytical data used to calculate CO_2 mass emissions under this appendix.

5.1 Missing Carbon Content Data Prior to 1/1/2000

Prior to January 1, 2000, follow either the procedures of this section or the procedures of section 5.2 of this appendix to substitute for missing carbon content data. On and after January 1, 2000, use the procedures of section 5.2 of this appendix to substitute for missing carbon content data, not the procedures of this section.

5.1.1 Most Recent Previous Data

Substitute the most recent, previous carbon content value available for that fuel type (gas, oil, or coal) of the same grade (for oil) or rank (for coal). To the extent practicable, use a carbon content value from the same fuel supply. Where no previous carbon content data are available for a particular fuel type or rank of coal, substitute the default carbon content from Table G–1 below.

5.1.2 [Reserved]

5.2 Missing Carbon Content Data on and After 1/1/2000

Prior to January 1, 2000, follow either the procedures of this section or the procedures of section 5.1 of this appendix to substitute for missing carbon content data. On and after January 1, 2000, use the procedures of this section to substitute for missing carbon content data.

5.2.1 Missing Weekly Samples

If carbon content data are missing for weekly coal samples or composite oil samples from continuous sampling, substitute the highest carbon content from the previous four carbon samples available. If no previous carbon content data are available, use the default carbon content from Table G–1, below.

5.2.2 Manual Sample From Storage Tank

If carbon content data are missing for manual oil or diesel fuel samples taken from the storage tank after transfer of a new delivery of fuel, substitute the highest carbon content from all samples in the previous calendar year. If no previous carbon content data are available from the previous calendar year, use the default carbon content from Table G–1, below.

5.2.3 As-Delivered Sample

If carbon content data are missing for as-delivered samples of oil, diesel fuel, or gaseous fuel delivered in lots, substitute the highest carbon content from all deliveries of that fuel in the previous calendar year. If no previous carbon content data are available for that fuel from the previous calendar year, use the default carbon content from Table G–1, below.

5.2.4 Sample of Gaseous Fuel Supplied by Pipeline

If carbon content data are missing for a gaseous fuel that is supplied by a pipeline and sampled on either a monthly or a daily basis for sulfur and gross calorific value, substitute the highest carbon content available for that fuel from the previous calendar year. If no previous carbon content data are available for that fuel from the previous calendar year, use the default carbon content from Table G–1, below.

TABLE G–1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA

Parameter	Sampling technique/frequency	Missing data substitution procedure
Oil and coal carbon content	All oil and coal samples, prior to January 1, 2000	Most recent, previous carbon content value available for that grade of oil.
	Weekly coal sample or Flow proportional/weekly composite oil sample (beginning no later than January 1, 2000).	Highest carbon in previous 4 weekly samples.
	In storage tank (after addition of fuel to tank) (beginning no later than January 1, 2000).	Maximum carbon content from all samples in previous calendar year.
	As delivered (in delivery truck or barge) (beginning no later than January 1, 2000).	Maximum carbon content from all deliveries in previous calendar year.
Gas carbon content	All gaseous fuel samples, prior to January 1, 2000	Most recent, previous carbon content value available for that type of gaseous fuel.
	Gaseous fuel in lots—as-delivered sampling (beginning no later than January 1, 2000).	Maximum carbon content of all samples in previous calendar year.
	Gaseous fuel delivered by pipeline that is sampled for sulfur content—daily sampling (beginning no later than January 1, 2000).	Maximum carbon content of all samples in previous calendar year.
	Pipeline natural gas that is not sampled for sulfur content—monthly sampling for GCV and carbon only (beginning no later than January 1, 2000).	Maximum carbon content of all samples in previous calendar year.
Default coal carbon content	All	Anthracite: 90.0 percent. Bituminous: 85.0 percent. Subbituminous/Lignite: 75.0 percent.
Default oil carbon content	All	90.0 percent.

TABLE G–1.—MISSING DATA SUBSTITUTION PROCEDURES FOR MISSING CARBON CONTENT DATA—Continued

Parameter	Sampling technique/frequency	Missing data substitution procedure
Default gas carbon content ..	All	Natural gas: 75.0 percent. Other gaseous fuels: 90.0 percent.

5.3 Gross Calorific Value Data

For a gas-fired unit using the procedures of section 2.3 of this appendix to determine CO_2 emissions, substitute for missing gross calorific value data used to calculate heat input by following the missing data procedures for gross calorific value in section 2.4 of appendix D to this part.

Appendix H To Part 75—Revised Traceability Protocol No. 1

75. Appendix H to part 75 is removed and reserved.

76. Appendix I to part 75 is added as follows:

Appendix I To Part 75—Optional F-Factor/Fuel Flow Method

1. Applicability

1.1 This procedure may be used in lieu of continuous flow monitors for the purpose of determining volumetric flow from gas-fired units, as defined in § 72.2 of this chapter, or oil-fired units, as defined in § 72.2 of this chapter, provided that the units burn only pipeline natural gas, natural gas, and/or fuel oil. These procedures use fuel flow measurement, fuel sampling data, CO_2 (or O_2) CEMS data, and F-factors to determine the flow rate of the stack gas. These procedures may only be used during those hours when only one type of fuel is combusted.

1.2 Apply to the Administrator, in a certification application, for approval to use this method in lieu of a continuous flow monitor, no later than the deadlines for the certification of continuous emission monitoring systems specified in §§ 75.20 and 75.63.

2. Procedure

2.1 Initial Certification and Recertification Testing

Either of the following procedures may be used to perform initial certification and recertification testing of the appendix I excepted flow monitoring system:

2.1.1 Component-by-Component Certification Testing

Test both the fuel flowmeter component and the CO_2 (or O_2) monitor component separately, following the procedures of this part. Determine BAF_{System} and BAF_{CO2} or BAF_{O2}, using the procedures in section 3.7 of this appendix.

2.1.1.1 Certification of the Fuel Flowmeter

Test the fuel flowmeter according to the procedures and performance specifications in section 2.1.5 of appendix D to this part.

2.1.1.2 Certification of the CO_2 (or O_2) Monitor

Test the CO_2 or O_2 monitor according to the procedures and performance specifications in appendix A to this part. Notwithstanding the requirements of appendix A to this part, calculate the BAF of the CO_2 or O_2 monitor according to section 3.7 of this appendix.

2.1.2 System Certification Testing

Test the entire appendix I flow monitoring system to meet the relative accuracy requirements for flow, as found in section 3.3.4 of appendix A to this part, using the applicable procedures in sections 6.5 through 6.5.2.2 of appendix A to this part. Use the fuel sampling data for density and carbon content to calculate the hourly volumetric flow rate according to section 2.3 of this appendix. Perform the bias test and, if necessary, calculate a bias adjustment factor for the appendix I flow monitoring system using the procedures in section 7.6 of appendix A to this part. Also perform the 7-day calibration error test, cycle time test, and linearity check on the CO_2-or O_2-diluent monitor.

2.2 On-Going Quality Assurance Testing

2.2.1 Daily Assessments

The CO_2 or O_2 monitor shall meet the daily assessment requirements in section 2.1 of appendix B to this part.

2.2.2 Quarterly Assessments

The CO_2 or O_2 monitor shall meet the quarterly assessment requirements in section 2.2 of appendix B to this part.

2.2.3 Semiannual or Annual Assessments

2.2.3.1 Component-by-Component Assessments

Test both the fuel flowmeter and the CO_2 (or O_2) monitor separately. Determine BAF_{System} and BAF_{CO2} or BAF_{O2} using the procedures in section 3.7 of this appendix.

2.2.3.1.1 Assessment of the Fuel Flowmeter

The fuel flowmeter shall meet the periodic quality assurance requirements in section 2.1.6 of appendix D to this part. The fuel flowmeter shall meet the flowmeter accuracy specification in section 2.1.5 of appendix D to this part.

2.2.3.1.2 Relative Accuracy Assessment of the CO_2 (or O_2) Monitor

Test the CO_2 or O_2 monitor for relative accuracy according to the applicable procedures in sections 6.5 through 6.5.2.2 of appendix A to this part. Determine the relative accuracy test frequency (i.e., semiannual or annual) using section 2.3.1 and figure 2 in appendix B to this part. Perform the bias test and calculate any bias adjustment factor, as specified in section 3.7.1 of this appendix for the CO_2 monitor or as specified in section 3.7.2 of this appendix for the O_2 monitor.

2.2.3.2 System Relative Accuracy Assessment

Test the entire appendix I flow monitoring system to meet the relative accuracy requirements for flow, as found in section 3.3.4 of appendix A to this part, using the procedures in section 6.5.2 of appendix A to this part. Use Reference Method 2 (or its allowable alternatives) in appendix A to part 60 of this chapter to obtain the reference method flow rate value for each run. Use the appropriate equation selected from Eq. I–1 through Eq. I–9 to calculate the Appendix I flow rate value for each RATA run. Base the fuel sampling on section 2.3 of this appendix. Determine the schedule for future relative accuracy tests using the provisions of section 2.3.1 and figure 2 of appendix B to this part for a flow monitoring system. Perform the bias test and, if necessary, calculate a bias adjustment factor for the appendix I flow monitoring system using the procedures in section 7.6 of appendix A to this part.

2.3 Fuel Sampling and Analysis

2.3.1 Carbon Content of Oil

Determine carbon content of the oil by using the following procedures. Collect at least one sample per each shipment for oil and diesel fuel. Determine the carbon content of the fuel sampling using one of the following methods: ASTM D5291–92 ''Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants,'' ultimate analysis of oil, or computations based upon ASTM D3238–90 and either ASTM D2502–87 or ASTM D2503–82 (Reapproved 1987) for oil.

2.3.2 Density of Oil

Determine the density of oil using the procedures in section 2.2 of appendix D to this part.

2.3.3 Gross Calorific Value of Natural Gas

Determine gross calorific value of natural gas by using the procedures in section 5.5.2 of appendix F to this part.

3. Calculations

3.1 Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use a CO_2 Monitor and a Volumetric Oil Flowmeter

$$Q_s = \frac{32.08 \times V \times \rho \times \%C}{\%CO_2}$$

(Eq. I–1)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–10A or I–10B (for component-by-component testing) in section 3.7 of this appendix or by Equation I–11 (for system testing) in section 3.8 of this appendix.

V=Volumetric oil flow rate, gal/hr.

ρ=Oil density, lb/gal.

%C=Percent carbon by weight.

$\%CO_2$=CO_2 concentration, percent by volume.

32.08=Conversion factor, 385 scf CO_2/12 lb C, volume of CO_2 emitted for each pound carbon in oil.

3.2 Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use an O_2 Monitor and a Volumetric Oil Flowmeter

3.2.1 If relative accuracy is determined on a system basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times BAF_{system} \times V \times \rho \times \%C \times (20.9)(100)}{(20.9 - \%O_{2d}) \times (100 - \%H_2O)}$$

(Eq. I–2)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–11 (for system testing) in section 3.8 of this appendix.

V=Volumetric oil flow rate, gal/hr.

ρ=Oil density, lb/gal.

%C=Percent carbon by weight.

$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.

$\%H_2O$=Percent moisture in the flue gas.

207.6379=Conversion factor, 385 scf CO_2/12 lb C×9190 dscf O_2/1420 scf CO_2, volume of O_2 emitted for each pound carbon in oil.

3.2.2 If relative accuracy is determined on a component by component basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times 1.12 \times V \times \rho \times \%C \times (20.9)(100)}{\left[20.9 - (BAF_{O2} \times \%O_{2d})\right] \times (100 - \%H_2O)}$$

(Eq. I–3)

Where:

Q_s Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{O2}=Bias adjustment factor for the O_2 monitor, as determined by section 3.7.2 of this appendix.

V=Volumetric oil flow rate, gal/hr.

ρ=Oil density, lb/gal.

%C=Percent carbon by weight.

$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.

$\%H_2O$=Percent moisture in the flue gas.

1.12=Default multiplier used to compensate for systematic error in the demonstration data.

207.6379=Conversion factor, 385 scf CO_2/12 lb C×9190 dscf O_2/1420 scf CO_2, volume of O_2 emitted for each pound carbon in oil.

3.3 Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use a CO_2 Monitor and a Mass Oil Flowmeter

$$Q_s = \frac{32.08 \times BAF_{system} \times M \times \%C}{\%CO_2}$$

(Eq. I–4)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–10A or I–10B (for component by component testing) in section 3.7 of this appendix or by Equation I–11 (for system testing) in section 3.8 of this appendix.

M=Oil mass flow rate, lb/hr.

%C=Percent carbon by weight.

$\%CO_2$=CO_2 concentration, percent by volume.

32.08=Conversion factor, 385 scf CO_2/12 lb C, volume of CO_2 emitted for each pound carbon in oil.

3.4 Hourly Volumetric Flow during Combustion of Oil Only for Systems that Use an O_2 Monitor and a Mass Oil Flowmeter

3.4.1 If relative accuracy is determined on a system basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times BAF_{system} \times M \times \%C \times (20.9)(100)}{(20.9 - \%O_{2d}) \times (100 - \%H_2O)}$$

(Eq. I–5)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–11 (for system testing) in section 3.8 of this appendix.

M=Oil mass flow rate, lb/hr.

%C=Percent carbon by weight.

$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.

$\%H_2O$=Percent moisture in the flue gas.

207.6379=Conversion factor, 385 scf CO_2/12 lb C×9190 dscf O_2/1420 scf CO_2, volume of O_2 emitted for each pound carbon in oil.

3.4.2 If relative accuracy is determined on a component by component basis, use the following equation to determine the volumetric stack flow rate:

$$Q_s = \frac{207.6379 \times 1.12 \times M \times \%C \times (20.9)(100)}{\left[20.9 - (BAF_{O2} \times \%O_{2d})\right] \times (100 - \%H_2O)}$$

(Eq. I–6)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{O2}=Bias adjustment factor for the O2 monitor, as determined by section 3.7.2 of this appendix.

M=Oil mass flow rate, lb/hr.

%C=Percent carbon by weight.

$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.

$\%H_2O$=Percent moisture in the flue gas.

1.12=Default multiplier used to compensate for systematic error in the demonstration data.

207.6379=Conversion factor, 385 scf CO_2/12 lb C×9190 dscf O_2/1420 scf CO_2, volume of O_2 emitted for each pound carbon in oil.

3.5 Hourly Volumetric Flow during Combustion of Natural Gas Only for Systems that Use a CO_2 Monitor and a Volumetric Gas Flowmeter

$$Q_s = \frac{0.01 \times BAF_{system} \times V \times GCV \times F_c}{\%CO_2}$$

(Eq. I–7)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–10A or I-10B (for component by component testing) in section 3.7 of this appendix or by Equation I–11 (for system testing) in section 3.8 of this appendix.

V=Volumetric gas flow rate, 100 scfh.

GCV=Gross calorific value of the gaseous fuel, Btu/scf.

F_c=Carbon-based F-factor of 1040 scf CO_2/mmBtu for natural gas, from section 3 of appendix F to this part.

$\%CO_2$=CO_2 concentration, percent by volume.

0.01=Conversion factor, 10^{-6} mmBtu/Btu×10^2 scf/100 scf×10^2 (conversion of fraction to percentage).

3.6 Hourly Volumetric Flow during Combustion of Natural Gas Only for Systems that Use an O_2 Monitor and a Volumetric Gas Flowmeter

3.6.1 Determining Flow for Systems that Are Tested on a System Basis

$$Q_s = \frac{0.01 \times BAF_{system} \times V \times GCV \times F_d \times (20.9)(100)}{(20.9 - \%O_{2d}) \times (100 - \%H_2O)}$$

(Eq. I–8)

Where:

Q_2=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{system}=Bias adjustment factor for the system, as determined by Equation I–11 (for system testing) in section 3.8 of this appendix.

V=Volumetric gas flow rate, 100 scfh.

GCV=Gross calorific value of the natural gas, Btu/scf.

F_d=Dry basis, O_2-based F-factor for natural gas, 8,710 dscf/mmBtu.

$\%O_{2d}$=Dry basis O_2 concentration, percent by volume.

$\%H_2O$=Percent moisture in the flue gas.

0.01=Conversion factor, 10^{-6} mmBtu/Btu x 10^2 scf/100 scf×10^2 (conversion of fraction to percentage).

3.6.2 Determining Flow for Systems that are Tested on a Component-by-Component Basis

$$Q_s = \frac{0.01 \times 1.12 \times V \times GCV \times F_d \times (20.9)(100)}{\left[20.9 - (BAF_{O2} \times \%O_{2d})\right] \times (100 - \%H_2O)}$$

(Eq. I–9)

Where:

Q_s=Volumetric stack flow rate, adjusted for bias, in scfh.

BAF_{O2}=Bias adjustment factor for the O_2 monitor, as determined by section 3.7.2 of this appendix.

V=Volumetric gas flow rate, 100 scfh.

GCV=Gross calorific value of the natural gas, Btu/scf.

F_d=Dry basis, O_2-based F-factor for natural gas, 8,710 dscf/mmBtu.

$\%O2_{2d}$=Dry basis O_2 concentration, percent by volume.

$\%H_d2O$=Percent moisture in the flue gas.

1.12=Default multiplier used to compensate for systematic error in the demonstration data.

0.01=Conversion factor, 10^{-6} mmBtu/Btu x 10^2 scf/100 scf x 10^2 (conversion of fraction to percentage).

3.7 Bias Adjustment Factor for a System Tested Component-by-Component

3.7.1 Calculation of the System Bias Adjustment Factor, $BAF_{system,}$ for CO_2 Monitor

Calculate the mean difference of the relative accuracy test data for the CO_2 monitor, $\bar{d}$, using Equation A–7 in section 7.3.1 of appendix A to this part. Calculate the confidence coefficient (cc) using Equation A–9 in section 7.3.3 of appendix A to this part. If $\bar{d}$ < -cc, where $\bar{d}$ is defined by Equation A–7, calculate the bias adjustment factor for a system tested component by component, as follows:

$$BAF_{system} = \frac{1.12}{\left(1 + \frac{\bar{d}}{\overline{CEM}}\right)}$$

(Eq. I–10A)

If d ≥ -cc, then

BAF_{system}=1.12

(Eq. I–10B)

Where:

BAF_{system}=Overall bias adjustment factor for the appendix I flow monitoring system.

1.12=Default multiplier used to compensate for systematic error in the demonstration data.

$\bar{d}$=Mean difference between the reference method and continuous emission monitoring system (RM_i-CEM_i) as defined in Equation A–7 in section 7.3.1 of appendix A to this part.

$\overline{CEM}$=Mean of the data values provided by the CO_2 monitor during the relative accuracy test audit.

3.7.2 Calculation of the Component Bias Adjustment Factor, BAF_{O2}, for O_2 Monitor

Perform the bias test for the O_2 monitor using the procedures in section 7.6 of appendix A to this part and, if necessary, calculate a bias adjustment factor.

3.8 Bias Adjustment Factor for a System Tested on a System Level

Calculate the bias adjustment factor for a system tested on a system level, as follows:

BAF_{System}=$GAF_{flow\ rate}$

(Eq. I–11)

Where:

BAF_{system}=Overall bias adjustment factor for the appendix I flow monitoring system.

$BAF_{flow\ rate}$=Bias adjustment factor from relative accuracy testing using Reference Method 2 for volumetric flow rate.

4. Missing Data

4.1 The owner or operator shall provide substitute volumetric flow data using the flow missing data procedures in subpart D of this part.

4.2 [Reserved]

5. Recordkeeping and Reporting

Follow the applicable monitoring plan provisions of § 75.53, the applicable general recordkeeping provisions of § 75.57, the specific recordkeeping provisions of § 75.58(g), the certification recordkeeping provisions of § 75.59(d)(1), and the quality assurance test recordkeeping provisions of § 75.59(d)(2). Maintain a quality assurance/quality control plan, as specified in appendix

B to this part. Follow the reporting provisions of §§ 75.60 through 75.67.

77. Appendix J to part 75 is removed and reserved.

[FR Doc. 98–11749 Filed 5–20–98; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 75

[FRL–6007–7]

RIN 2060–AH64

Acid Rain Program: Determinations under EPA Study of Bias Test and Relative Accuracy and Availability Analysis

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of proposed determinations and proposed rulemakings.

SUMMARY: Title IV of the Clean Air Act Amendments of 1990 (the Act) authorizes EPA to establish a program to reduce the adverse effects of acidic deposition. The Act requires electric utilities affected by the Acid Rain Program to install continuous emission monitoring systems (CEMS) to measure emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2). On January 11, 1993, Continuous Emission Monitoring regulations were published. They established procedures and requirements for installing, certifying, operating, and quality assuring CEMS at Acid Rain affected utility units. In response to comments and litigation from representatives of the electric utility industry and environmental advocacy groups, provisions were incorporated in the CEMS regulations requiring EPA to conduct studies, reach determinations, and, if necessary, initiate rulemakings on the appropriateness of retaining or revising three elements in the CEMS regulations: the bias test, relative accuracy test, and the availability trigger conditions of the Missing Data Substitution Procedure. This Notice of Proposed Rulemaking presents EPA's proposed determinations and consequent proposed rule revisions.

DATES: *Comments.* Comments on the proposed determinations and rule revisions must be received on or before July 6, 1998.

Public Hearing. Anyone requiring a public hearing must contact EPA no later than June 1, 1998. If a hearing is held, it will take place June 5, 1998, beginning at 10:00 a.m.

ADDRESSES: *Comments.* All written comment must be identified with the appropriate docket number (Docket No. A–97–56) and must be submitted in duplicate to EPA Air Docket Section (6102), Waterside Mall, Room M1500, 1st Floor, 401 M Street, SW, Washington, D.C. 20460.

Public Hearing. If a public hearing is requested, it will be held at the Environmental Protection Agency, 401 M Street, SW, Washington, D.C. 20460, in the Education Center Auditorium. Refer to the Acid Rain homepage at www.epa.gov/acidrain for more information or to determine if a public hearing has been requested and will be held.

Docket. Docket No. A–97–56, containing supporting information used to develop the proposed determinations and rule revisions is available for public inspection and copying from 8:00 a.m. to 5:30 p.m., Monday through Friday, excluding legal holidays, at EPA's Air Docket Section at the above address.

FOR FURTHER INFORMATION CONTACT: Elliot Lieberman at (202) 564 9136, Acid Rain Division (6204J), U.S. Environmental Protection Agency, 401 M St., S.W., Washington, D.C. 20460; or the Acid Rain Hotline at (202) 564 9620. Electronic copies of this notice and technical support documents can be accessed through the Acid Rain Division website at http://www.epa.gov/acidrain.

SUPPLEMENTARY INFORMATION:

I. EPA Studies Under 40 CFR 75.7
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B. Collaborative Field Study
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I. EPA Studies Under 40 CFR 75.7

A. Background

To ensure a consistent level of precision and accuracy in the emission measurements obtained across the Acid Rain Program, Part 75 of the Acid Rain regulations requires a series of performance tests to be conducted on each CEMS both at initial certification and periodically thereafter. Among the required performance tests is the relative accuracy test audit (RATA) in which a minimum of nine simultaneous measurements are taken from a unit's installed CEMS and an EPA approved reference method. The paired RATA data are then subjected to two statistical tests: The relative accuracy test, which establishes the degree of accuracy of the CEMS relative to the reference method; and the bias test, which uses a t-statistic to determine if the CEMS measurements are consistently lower than the reference method measurements. *See* 40 CFR Part 75, Appendix A and B.

As stated in the preamble of the January 1993 regulations, EPA found that ''both statistical theory and field test results show that the bias test is a sound and effective statistical procedure for detecting consistent measurement error in the long-term operation of a CEMS'' (58 FR 3590, 3627 (1993)). However, at the time of promulgation of the Acid Rain regulations, although utilities had extensive experience with the relative accuracy test, they had virtually no previous experience with the bias test. This unfamiliarity led to several concerns with the bias test. Thus, the January 1993 regulations committed EPA to conduct field studies to determine ''whether there are statistically significant variances'' in the EPA-approved reference methods that utilities use to test the performance of the CEMS installed under the Acid Rain Program and ''whether the bias test should be adjusted to compensate for statistical variances in the reference method'' (58 FR 3628).

In particular, EPA was required to:

1. Investigate whether there are statistically significant variances in the EPA reference methods (Issue #1);

2. Distinguish between the variability in reference monitor readings attributable to measurement error and the variability due to the choice of reference monitor among those certified by the Agency (Issue #2);

3. Investigate possible differences in bias test failure rates by emission levels (Issue #3); and

4. Assess whether any adjustments are necessary to properly determine measurement bias (Issue #4).

The regulations called for the completion of a study addressing these issues by October 31, 1993. In response, EPA conducted two studies. The first was a collaborative field study, involving four independent reference method test teams, at Big Rivers Electric Corporation's Green Generating Station, Unit 2, in Sebree, Kentucky. This location was specifically selected for testing because its relatively low range of SO_2 emission concentrations (from 56 ppm to 231 ppm) would allow EPA to examine bias test failure rates at SO_2 emission levels different from those prevailing in previous field studies and consider an industry concern that

contradictory bias test results were more likely to occur at low, than at high, emission concentrations. Field work for this study was completed from August 16–31, 1993. Separate data summary (Docket Item, A–97–56, II–A–1) and statistical analyses reports summary (Docket Item, A–97–56, II–A–2) were completed in March 1994 and September 1996 respectively.

The second study involved collection and analysis of bias test results from the field tests conducted by affected units under Part 75 for certification of their CEMS. The certification test data, including the bias test, were submitted to EPA from November 1993 to September 1996. The study results reported here (and contained in Docket Item, A–97–56, II–A–3) were available in 1997 only after the CEMS at the majority of both Phase I and Phase II (lower emitting) units had been received and certified by EPA.

B. Collaborative Field Study

In the collaborative field study at Unit 2 of Big Rivers Electric Corporation's Green Generating Station (''Green Unit 2''), four labs (i.e., test teams) simultaneously performed Reference Methods 6C (for SO_2), 7E (for NO_X), and 3A (for CO_2). To test the two general monitoring technologies available for performing the reference methods, two of the teams used ''wet-basis'' sampling techniques and two used ''dry-basis'' techniques. In the ''wet-basis'' sampling techniques, a dilution probe is used to extract a diluted sample of the effluent from the stack gas. The diluted gas sample is then analyzed using an ambient-level analyzer (e.g., pulsed fluorescence for SO_2, chemiluminescence for NO_X, and infrared absorption for CO_2), which does not require removal of moisture from the gas sample. In the ''dry-basis'' sampling techniques, a gas sample is extracted from the effluent stream without dilution. Moisture is condensed from the gas sample and the resulting dry sample is then analyzed using a source-level analyzer (infrared or ultraviolet for SO_2, chemiluminescence for NO_X, and infrared for CO_2).

Seventy-two runs of usable data (out of 76 total runs) were collected by the four labs. Concurrent measurements were also collected from Green Unit 2's SO_2, NO_X, and CO_2 continuous emissions monitoring systems, previously certified under the Acid Rain Program. On 36 of the runs, each lab and the unit's CEMS used separate calibration gases as required under 40 CFR Part 75. On the other 36 runs, all labs and the plant's CEMS shared common gases when calibrating.

Issues #1 and #2 involve evaluation of the sources of variability inherent in EPA's reference methods. In the consideration of these two issues only the reference method measurements were analyzed, not the unit's CEMS. Issues #3 and #4 involve a comparison of the CEMS and the reference method measurements to determine if bias (systematic error) is detected in the CEMS measurement. In the consideration of these two issues, the unit's CEMS measurements were paired with each of the four lab's concurrent reference method measurements. This produced four sets of concurrent Relative Accuracy Test Audits (RATA's) which could be used in evaluating bias test result consistency across the four labs.

To address the first two issues concerning the sources and extent of variability inherent in the reference methods, the collaborative field study employed an experimental design (technically known as a ''randomized complete block design'') which allowed the quantification of the relative variability associated with (i) among-laboratory variation, (ii) variation between monitoring technologies (i.e., ''wet-basis'' or ''dry-basis'' sampling techniques), (iii) the variability associated with different calibration gas scenarios (i.e., separate or shared calibration gases), and (iv) random error.

Applying an analysis of variance (ANOVA) statistical procedure to the field study data, EPA found that the overall variation in the reference methods, considering all the monitoring technologies and calibration gas scenarios, was 2.93%RSD (Relative Standard Deviation) for SO_2, 2.01%RSD for NO_X, and 1.59%RSD for CO_2. Reference method variations below approximately 3%RSD are consistent with the findings of an earlier collaborative field study, reported in Docket Item, A–97–56, II–A–5, where variations of 1.4%RSD and 2.9%RSD were found for SO_2 and NO_X respectively. (The variation for CO_2 is not available from the earlier study since that study did not include CO_2 reference method measurements.) Based on these findings, with respect to Issue #1 EPA believes that the statistically significant variances in the EPA reference methods are small.

The analysis in the most recent collaborative study also revealed that the range in the Relative Standard Deviation due to the choice of reference method monitor (i.e., different analyzers using ''wet-basis'' or ''dry-basis'' technology) among allowable reference method technologies was very small (below 1%RSD) whether the labs used separate or shared calibration gases. Consequently, EPA believes with respect to Issue #2 that the variability due to the choice of reference method monitor among those available is very small.

As noted earlier, Issues #3 and #4 require consideration of simultaneous measurements by the unit's CEMS along with the four test labs. To respond to Issue #3, concerning the consistency of the bias test results, the field test data were analyzed to determine how much agreement was found among the four labs as to whether the CEM was biased or not biased when current provisions of Part 75 are followed. In particular, the consistency in bias test results was evaluated by counting the number of concurrent RATA's in which agreement among the four test teams was 100% (all four labs agree), 75% (three out of four labs agree) and 50% (two labs find bias and two find no bias). For each pollutant there was never less than 75% agreement among the test teams when the reference methods and the installed CEMS were each calibrated using independently selected calibration gases, as is required under 40 CFR Part 75. For NO_X and CO_2 there was always 100% agreement. For SO_2 there was 100% agreement in bias test results in more than 76% of the concurrent RATA's.

These test results lead EPA to believe that even at a site exhibiting low SO_2 emission concentrations, there is a high degree of consistency in bias test results.

C. Certification Test Study

To respond further to Issue #3, EPA analyzed the consistency in bias test results across the universe of affected units, by conducting a study of the bias test results for all CEMS for which certification tests data were submitted under Part 75 between November 1993 and September 1996. To see how test results were affected by emission levels, the pass/fail rates at different concentrations (SO_2) and emission rates (NO_X) were compared for 1023 SO_2 and 1293 NO_X bias tests submitted under the Acid Rain Program. This analysis was not performed on CO_2 monitors, because under Part 75 units are not required to perform the bias test on their CO_2 monitors.

Grouping monitors according to the average concentration level (for SO_2 CEMS) and average emission rate (for NO_X CEMS), reported by the CEMS during the RATA, the pass/fail rates were plotted at regular increasing SO_2 emission concentration levels and NO_X emission rates. The resulting graphs revealed that the percentage of passes and fails remained relatively consistent

across concentration and emission rate categories. For example, for all SO_2 monitors, 73% (750 out of a total of 1023 monitors) passed the bias test. Assigning each tested monitor to one of fourteen 100 ppm categories, beginning at 0–100 ppm and ending at above 1300 ppm, showed that the percent of passing monitors in all but three of the concentration categories fell between 70 and 90%. The three categories whose passing rates were outside this range were 400–500 ppm (56% passing), 600–700 ppm (69%), and above 1300 ppm (63%). Thus, there was little or no apparent correlation between concentration level and bias test failure rates.

The graphical analysis for SO_2 monitors was confirmed by calculation of the r-squared value for the data. The r-squared value is a measure of the strength of the linear relationship between two data sets. R-squared can take on values from zero to one. A high r-squared value, i.e., closer to 1 than to 0, would suggest that the bias test pass/fail rate is highly correlated with the emission concentration level, e.g., that bias test failure is more likely with low emission concentration as suggested by utilities. A low r-squared value, i.e., closer to 0 than to 1, would suggest the absence of correlation between the bias pass/fail rate and the emission concentration level. For the plotted SO_2 data, the r-squared value was low: 0.0109.

The same graphical and statistical analysis was performed on the certification test data submitted for NO_X CEMS. Bias test pass/fail rates for 1293 NO_X monitors were divided into sixteen 0.1 lb/mmBTU categories. Considering all these categories, 67% (866 out of a total of 1293 monitors) passed the bias test. A plot of the data by emission category showed the bias test passing rate fell between 65% and 85% in all but of 3 of the 16 NO_X emission categories. The three emission rate categories whose passing rates were outside this range were not correlated to the measured NO_X emission rate: 0.1–0.2 lb/mmBTU (47% passing), 0.4–0.5 lb/mmBTU (59%), and 1.4–1.5 lb/mmBTU (50%). Again, there was little or no apparent correlation between bias test pass/fail rates and emission rate, and this was confirmed by the statistical analysis. The r-squared value for the NO_X data was low: 0.1109.

Thus, the graphical and statistical analysis performed in the certification test study indicates consistent bias test results across emission levels.

D. Proposed Findings and Conclusions

Based on the analyses performed to address Issues #1–3 in the collaborative and certification field studies, EPA considered Issue #4, concerning the necessity and feasibility of adjustments to the bias test. EPA currently believes that the small variability in the reference methods (less than 3%RSD across all gas scenarios and monitor technologies) indicates that there is very low probability that a continuous emission monitoring system will fail the bias test for reasons other than the presence of true measurement bias in the CEMS. The high level of consistency in bias test results seems to support this view.

Based on these studies, EPA proposes to find that:

1. The variability attributable to measurement error and to the choice of reference monitor technology in the Agency's approved test methods for SO_2, NO_X, and CO_2 is low (below 3.0% Relative Standard Deviation).

2. Differences in measurement variability among different allowable reference method technologies are small (below 1.0% RSD).

3. There is a high occurrence of consistency in bias test results.

4. There is no evidence that bias test failure rates are significantly influenced by emission levels.

Documentation of these proposed findings can be found in four docket items: A Collaborative Field Evaluation of EPA Test Methods 6C, 7E, and 3A (March 1994) (Docket Item, A–97–56, II–A–1) gives a detailed description of the collaborative field test activities, site characteristics, and equipment employed, presents data obtained in the field study, and discusses preliminary findings on the variability of the reference methods. A second report, An Operator's Guide to Eliminating Bias in CEM System (November 1994) (Docket Item, A–97–56, II–A–6) is an independent technical guidance document advising environmental technicians on procedures for detecting and correcting engineering problems that could produce measurement bias in CEM systems. A third report, Statistical Analysis of Reference Method Variability and Bias Test Consistency in the Collaborative Field Study of EPA Test Methods 6C, 7E, and 3A at Big Rivers Electric Corporation, Green Generating Station, Unit 2 (September 1996) ((Docket Item, A–97–56, II–A–2), focuses on the analysis of the collaborative study field data, reports the results of this analysis with respect to the four issues that the study was designed to address, and, based on this analysis, makes recommendations concerning whether adjustments are needed to the bias test. Finally, the graphs and supporting data from the certification test study can be found in ''Bias Test Pass/Fail Rates at Different SO_2 and NO_X Emission Levels as Reported in Certification Relative Accuracy Test Audits (RATA's) submitted through September 1996 under 40 CFR Part 75.'' (December 1997) (Docket Items, A–97–56, II–A–3 and II–A–4).

Based on the proposed findings enumerated above, EPA proposes to determine that adjustments to the equations in the bias test are technically unnecessary to properly determine measurement bias. EPA therefore proposes not to initiate a rulemaking to change the bias test under § 75.7.

II. EPA Analyses in Response to 40 CFR 75.8

A. Background

In accordance with a settlement agreement, signed on April 17, 1995 in *Environmental Defense Fund* v. *Browner,* No. 93–1203 and consolidated cases (D.C. Cir., 1993), which addressed various CEMS issues, § 75.8 was adopted as part of the direct final rule, dated May 17, 1995, amending the January 11, 1993 rule's CEM provisions. Section 75.8 required EPA to evaluate the appropriateness of the current relative accuracy and availability trigger conditions for missing data substitution for SO_2, NO_X, and CO_2 CEMS and flow monitors. This evaluation was to be based on initial certification test data and quarterly report data for the 1993–1996 period. Using the evaluation, EPA was to determine whether to retain the current specifications or propose alternative performance specifications. A report evaluating this data was to be prepared by July 1, 1997, and EPA is to issue either a notice determining that the current rule provisions are appropriate or a notice proposing revisions. Any proposal revising the current rule is to be issued by October 31, 1997 and finalized by October 31, 1998. The results of EPA's evaluations of the current relative accuracy and availability trigger conditions are described below.

B. Relative Accuracy

Relative accuracy is a statistical indicator of how closely the measurements by an installed CEM approximate those obtained by a concurrently used EPA reference method during a 9–12 run field demonstration (known as the relative accuracy test audit (RATA)) that must

be performed periodically for each CEMS under Part 75. Relative accuracy is expressed as a percent deviation of the CEMS results from the reference method results. The lower the relative accuracy value for a CEMS, the closer its measurements are to the reference method. Under 40 CFR Part 75, Appendix A, § 3, and Appendix B, § 2.3.1, all SO_2, NO_X, and CO_2 CEMS are required to have in a RATA a relative accuracy of 10%. Those that have a superior relative accuracy of 7.5% or less have one year to undergo their next RATA. Those that have a relative accuracy equal to or less than the required 10% but greater than 7.5% must undergo their next RATA within six months. The tighter specification of 7.5% is referred to as the ''reduced frequency standard,'' while the 10% specification is known as the ''normal frequency standard.'' For flow monitors the normal frequency standard is 15%, while the reduced frequency standard is 10%. On January 1, 2000 the normal and reduced frequency standards for flow monitors will be lowered to correspond to the standards for the pollutant CEMS, i.e., 10% and 7.5% respectively.

The evaluation of initial certification test data submitted for 1993–1996 showed that the average relative accuracy was 3.42% for the 965 SO_2 CEMS installed under the Acid Rain Program, 3.62% for 1272 NO_X CEMS, 3.28% for 1097 CO_2 CEMS., and 6.88% for 1070 flow monitors. This means that for all pollutants and flow, the average relative accuracy was below the reduced frequency standard. Furthermore, 91.3% of all SO_2 CEMS, 94.1% of all NOx CEMS, 96.3% of all CO_2 CEMS, and 91.9% of all flow monitors met their respective reduced frequency standard. See Docket Item, A–97–56, II–A–7 for a complete analysis of the certification test relative accuracy results.

A similar evaluation was performed on the relative accuracy test results reported in quarterly reports for the 1994–1996 period. This analysis showed that the average relative accuracy over the three years of data was 3.49% on 2802 SO_2 RATAs, 3.67% on 3935 NO_X RATAs, 3.06% on 2736 CO_2 RATAs, and 5.78% on 3019 flow RATAs. Like the certification test results, the data in the quarterly reports indicate that for each type of monitor, the average relative accuracy was below the reduced frequency standard. In addition, on 96.2% of the SO_2 RATAs, 96.0% of the NO_X RATAs, 97.9% of the CO_2 RATAs, and 93.5% of flow RATAs, the monitors met their respective reduced frequency standard. A complete analysis of the quarterly report relative accuracy test results can be found in Docket Item, A–97–56, II–A–8.

The relative accuracy test results obtained by these installed CEMS imply that no appreciable improvement in achieved relative accuracies could be expected unless the relative accuracy standard were brought down to or below these currently achieved average relative accuracies. However, studies cited above (Docket Item, A–97–56, II–A–2 and II–A–5) of the variability of the reference methods for SO_2, NO_X, and CO_2 suggest that such reduced relative accuracy standards might be beyond the technological limits of current monitoring technology since they approach the variability inherent in the reference methods themselves. Thus, tightening the relative accuracy standards further for these CEMS is unlikely to produce a corresponding improvement in the achievable relative accuracy.

Moreover, the existing regulations already provide that the normal and reduced frequency relative accuracy standards for flow monitors will be tightened to the same levels as for the other CEMS beginning in the year 2000. In light of the already low average relative accuracy (reflecting high monitor accuracy) for flow monitors, there is little or no basis at this time for concluding that any further tightening would be appropriate. In addition, EPA believes that the results of the tightening in 2000 should be evaluated before any further tightening is contemplated.

Therefore, based on the evaluation required under § 75.8, the Agency proposes to conclude that the current performance specifications for relative accuracy are appropriate at this time.

C. Availability Trigger Conditions for Missing Data Substitution Procedure

In 40 CFR 75.30–75.38 (Subpart D) a missing data procedure is prescribed for calculating emissions when valid data are not being supplied by a unit's continuous emissions monitoring system. The missing data procedure is a multi-tiered computational routine for deriving a substitution value from values previously recorded, or the highest potential values, by the monitor. The procedure is based on the premise that the lower the annual monitor availability and/or the longer the gap in recorded data, the more conservative the value to be substituted.

In concert, two trigger conditions determine the conservativeness of the substituted value. The first trigger condition is annualized monitor availability, i.e., the percentage of the immediately preceding 8760 unit operating hours in which valid, quality assured data was obtained. The second trigger condition is the length of the current period during which valid data are not being produced. Current availability trigger conditions include three tiers: (1) less than 90% availability, (2) equal to or greater than 90% but less than 95% availability, and (3) 95% or greater availability.

To determine if retaining the current availability trigger conditions is appropriate, the Agency analyzed the annual percent monitor availability (PMA) as reported in the 1994–1996 quarterly emission reports. The PMA indicates the proportion of the operating hours in each year that the monitor was providing valid, quality assured measurements. High PMAs would indicate that current trigger conditions are providing a sufficient incentive for keeping monitors operating properly.

The evaluation of the quarterly report data for 1994–1996 showed that the average PMA for SO_2 CEMS was 94.7% in 1994, 96.7% in 1995, and 97.2% in 1996. For the same three year period it was 91.8%, 94.1%, and 95.8% for NOx CEMS, and 95.0%, 96.3%, and 97.0% for flow monitors. As a rule, separate percent monitor availabilities for the CO_2 CEMS are not routinely reported, since CO_2 CEMS usually serve as diluent components in NO_X systems. However, the average PMA for CO2 CEMS in a given year must be at least as good as the corresponding average of the reported NO_X PMAs. Not only are the average PMAs above the 95% availability trigger level, but they have also consistently increased in each successive year of the Acid Rain Program. To appreciably improve monitor availabilities would require increasing the third tier availability trigger up to or above the high average availabilities currently being achieved. EPA believes that such an increase in the required availabilities would be close to or beyond the limits of what is reasonable to expect from current CEMS technology when properly operated under the conditions prevailing in utility stacks. A complete summary of the PMA's submitted in the 1994–1996 quarterly reports can be found in Docket Item, A–97–56, II–A–9.

Moreover, any tightening of the availability trigger conditions would require reprogramming of most affected units' data acquisition and handling systems, which automatically calculate and record the appropriate substitution values for periods when valid CEMS data are not available. Given the current high levels of monitor availability, there is little or no basis for finding that adjusting the trigger conditions would improve availability sufficiently to

justify the reprogramming costs that such a change would impose.

Therefore, based on the evaluation required under § 75.8, the Agency proposes to determine that retaining the current performance specifications for availability trigger conditions is appropriate at this time.

III. Proposed Rule Revisions

Having completed the studies and evaluations required in 40 CFR 75.7 and 75.8 and in light of EPA's determinations proposed above for retaining current rule provisions for the bias test, relative accuracy, and availability trigger conditions, EPA proposes revising Part 75 to delete §§ 75.7 and 75.8.

IV. Administrative Requirements

A. Executive Order 12866

Under Executive Order 12866, 58 FR 51735 (1993), the Administrator must determine whether the regulatory action is ''significant'' and therefore subject to Office of Management and Budget (OMB) review and the requirements of the Executive Order. The Order defines ''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 affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities;

(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.

Pursuant to the terms of Executive Order 12866, it has been determined that this proposed rule is a ''significant regulatory action'' because the rule seems to raise novel legal or policy issues. As such, this action was submitted to OMB for review. Any written comments from OMB to EPA, any written EPA response to those comments, and any changes made in response to OMB suggestions or recommendations are included in the docket. The docket is available for public inspection at the EPA's Air Docket Section, which is listed in the **ADDRESSES** section of this preamble.

B. Unfunded Mandates Act

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Pub. L. 104–4, establishes requirements for federal agencies to assess the effects of their regulatory actions on State, local, and tribal governments and the private sector. Under section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, before promulgating a proposed or final rule that includes a federal mandate that may result in expenditure by State, local, and tribal governments, in aggregate, or by the private sector, of $100 million or more in any one year. Section 205 generally requires that, before promulgating a rule for which a written statement must be prepared, EPA 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 EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator explains why that alternative was not adopted. Finally, section 203 requires that, before establishing any regulatory requirements that may significantly or uniquely affect small governments, EPA must have developed a small government agency plan. The plan must provide for notifying any potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Because this proposed rule is estimated to result in the expenditure by State, local, and tribal governments or the private sector of less than $100 million in any one year, the Agency has not prepared a budgetary impact statement or specifically addressed the selection of the least costly, most cost-effective, or least burdensome alternative. Because small governments will not be significantly or uniquely affected by this rule, the Agency is not required to develop a plan with regard to small governments.

As discussed above, the proposed rule would eliminate two sections requiring studies and evaluations by EPA of certain existing regulatory provisions and would not include any other changes to the existing regulations. The proposed rule therefore would not change in any way the expenditure by State, local, and tribal governments or the private sector, or the effect on small governments, resulting from the existing regulations.

C. Paperwork Reduction Act

This action proposing revisions to the continuous emission monitoring regulations would not impose any new information collection burden. OMB has previously approved the information collection requirements contained in the continuous emission monitoring regulations, 40 CFR part 75, under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501, *et seq.* Note, however, that the Agency is proposing other revisions to the continuous emission monitoring regulations in a separate action in today's **Federal Register** and that those revisions would result in a change to the current information collection burden.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

D. Regulatory Flexibility

The Regulatory Flexibility Act, 5 U.S.C. 601, *et seq.*, generally requires federal agencies to conduct a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements unless the agency certifies that the proposed 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.

As discussed above, the proposed rule would eliminate two sections requiring studies and evaluations by EPA and would not include any other changes to the existing regulations. The proposed rule therefore does not change in any way the potential impacts on small entities resulting from the existing regulations. Therefore, I hereby certify

that this action will not have a significant economic impact on a substantial number of small entities.

List of Subjects in 40 CFR Part 75

Environmental protection, Air pollution control, Carbon dioxide, Continuous emissions monitors, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: April 27, 1998.

Carol M. Browner,

Administrator.

For the reasons set out in the preamble, part 75 of title 40, chapter 1 of the Code of Federal Regulations is proposed to be amended as follows:

PART 75—[AMENDED]

1. The authority citation for part 75 continues to read as follows:

Authority: 42 U.S.C. 7601 and 7651, *et seq.*

2. Section 75.7 is removed and reserved.

3. Section 75.8 is removed and reserved.

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federal register

Thursday
May 21, 1998

Part III

United States Sentencing Commission

Amendments to the Sentencing Guidelines for United States Courts; Notice

UNITED STATES SENTENCING COMMISSION

Amendments to the Sentencing Guidelines for United States Courts

AGENCY: United States Sentencing Commission.

ACTION: Notice of submission to Congress of amendments to the sentencing guidelines, policy statements, and official commentary; notice of proposed amendment for public comment.

SUMMARY: Pursuant to its authority under section 994(p) of title 28, United States Code, the United States Sentencing Commission, on May 1, 1998, submitted to the Congress amendments to the sentencing guidelines, policy statements, and official commentary together with reasons for the amendments. The amendments submitted to Congress are set forth in Part I of this notice.

In addition, pursuant to its authority under section 994(a), (o), and (p) of such title and section 2(g) of the No Electronic Theft Act of 1997, Pub. L. 105–147, the Commission is considering promulgating an amendment to the guidelines and commentary in order to implement directives to the Commission contained in the No Electronic Theft Act. The proposed amendment and a synopsis of the issues addressed are set forth in Part II of this notice. The Commission seeks comment on the proposed amendment, as well as alternative proposed amendments. Bracketed text within a proposal indicates alternative proposals and that the Commission invites comment and suggestions for appropriate policy choices.

DATES: Pursuant to 28 U.S.C. 994(p), the Commission has specified an effective date of November 1, 1998, for the amendments submitted to Congress, subject to their acceptability to Congress.

Written public comment on the amendments proposed to implement the directives in the No Electronic Theft Act of 1997 should be submitted not later than August 31, 1998.

ADDRESSES: Public comment on the amendment proposed to implement the directives in the No Electronic Theft Act of 1997 should be sent to: United States Sentencing Commission, One Columbus Circle, N.E., Suite 2–500, Washington, D.C. 20002–8002, Attention: Public Information.

FOR FURTHER INFORMATION CONTACT: Mike Courlander, Public Affairs Officer, telephone: (202) 273–4590.

SUPPLEMENTARY INFORMATION: The United States Sentencing Commission, an independent agency in the judicial branch of the U.S. Government, is empowered by 28 U.S.C. 994(a) to promulgate sentencing guidelines and policy statements for federal sentencing courts. The statute further directs the Commission to review periodically and revise guidelines previously promulgated and authorizes it to submit guideline amendments to the Congress not later than the first day of May each year. See 28 U.S.C. 994(o), (p). Additionally, a number of the amendments included in Part I of this report are authorized and directed by, or otherwise respond to, a variety of enactments of the 105th Congress. Absent action of Congress to the contrary, the amendments become effective on the date specified by the Commission (i.e., November 1, 1998) by operation of law.

Notice of the amendments submitted to the Congress on May 1, 1998, was first published in the **Federal Register** of January 6, 1998 (63 FR 602). Public hearings on the proposed amendments were held in San Francisco, CA, on March 5, 1998, and in Washington, DC, on March 12, 1998. After review of the hearing testimony and additional public comment, the Commission promulgated the amendments set forth in Part I below, each having been approved by at least four voting Commissioners.

In the **Federal Register** of January 6, 1998, the Commission also published a proposal from the Department of Justice on the implementation of the directives contained in the No Electronic Theft Act, as well as a general issue for comment on how these directives might best be carried out. The Commission heard testimony on these directives at the public hearing in Washington, DC, on March 12, 1998, and reviewed additional written public comment received on this issue in response to the **Federal Register** notice. The Commission also informally solicited and received the input of parties interested in copyright and trademark infringement sentencing issues, such as representatives of the Department of Justice, the defense bar, and other key groups, in an effort to determine how best to implement the directives. As a result of this input and after reviewing the hearing testimony and additional written public comment, the Commission voted, on April 23, 1998, to publish for comment the three proposals contained in Part II, below.

In connection with its ongoing process of guideline review, the Commission welcomes comment on any aspect of the sentencing guidelines, policy statements, and official commentary.

Authority: 28 U.S.C. 994(a), (o), (p).

Richard P. Conaboy

Chairman.

Part I—Amendments Submitted to Congress on May 1, 1998

1. *Amendment:* Section 2B1.1(b) is amended by adding at the end the following new subdivision:

''(8) If the offense involved theft of property from a national cemetery, increase by 2 levels.''.

The Commentary to § 2B1.1 captioned ''Application Notes'' is amended in Note 1 by adding at the end the following new paragraph:

''*National cemetery* means a cemetery (A) established under section 2400 of title 38, United States Code, or (B) under the jurisdiction of the Secretary of the Army, the Secretary of the Navy, the Secretary of the Air Force, or the Secretary of the Interior.''.

The Commentary to § 2B1.1 captioned ''Background'' is amended by adding at the end the following new paragraph:

''Subsection (b)(8) implements the instruction to the Commission in Section 2 of Public Law 105–101.''.

Section 2B1.3(b) is amended by adding at the end the following new subdivision:

''(4) If property of a national cemetery was damaged or destroyed, increase by 2 levels.''.

The Commentary to § 2B1.3 captioned ''Application Notes'' is amended in Note 1 by adding at the end the following new paragraph:

''*National cemetery* means a cemetery (A) established under section 2400 of title 38, United States Code, or (B) under the jurisdiction of the Secretary of the Army, the Secretary of the Navy, the Secretary of the Air Force, or the Secretary of the Interior.''.

The Commentary to § 2B1.3 captioned ''Background'' is amended by inserting before the first paragraph the following:

''Subsection (b)(4) implements the instruction to the Commission in Section 2 of Public Law 105–101.''.

Section 2K1.4(b) is amended by striking ''Characteristic'' and inserting ''Characteristics''; and by adding at the end the following new subdivision:

''(2) If the base offense level is not determined under (a)(4), and the offense occurred on a national cemetery, increase by 2 levels.''.

The Commentary to § 2K1.4 is amended by adding at the end the following new application note and background commentary:

''4. *National cemetery* means a cemetery (A) established under section

2400 of title 38, United States Code, or (B) under the jurisdiction of the Secretary of the Army, the Secretary of the Navy, the Secretary of the Air Force, or the Secretary of the Interior.

Background: Subsection (b)(2) implements the directive to the Commission in Section 2 of Public Law 105–101.''.

Reason for Amendment: The purpose of this amendment is to provide an increase for property offenses committed against national cemeteries. This amendment implements the directive to the Commission in the Veterans' Cemetery Protection Act of 1997, Pub. L. 105–101, § 2, 111 Stat. 2202, 2202 (1997). This Act directs the Commission to provide a sentence enhancement of not less than two levels for any offense against the property of a national cemetery. In response to the legislation, this amendment adds a two-level enhancement to §§ 2B1.1 (Theft), 2B1.3 (Property Destruction), and 2K1.4 (Arson). *National cemetery* is defined in the same way as that term is defined in the statute.

2. *Amendment:* Section 2F1.1(b) is amended by striking subdivision (5) in its entirety and inserting the following:

''(5) (A) If the defendant relocated, or participated in relocating, a fraudulent scheme to another jurisdiction to evade law enforcement or regulatory officials; (B) if a substantial part of a fraudulent scheme was committed from outside the United States; or (C) if the offense otherwise involved sophisticated concealment, increase by 2 levels. If the resulting offense level is less than level 12, increase to level 12.''.

Section 2F1.1(b) is amended by adding at the end the following new subdivision:

''(7) If the offense was committed through mass-marketing, increase by 2 levels.''.

The Commentary to § 2F1.1 captioned ''Application Notes'' is amended by redesignating Notes 14 through 18, as Notes 15 through 19, respectively; and by inserting after Note 13 the following new Note 14:

''14. For purposes of subsection (b)(5)(B), *United States* means each of the 50 states, the District of Columbia, the Commonwealth of Puerto Rico, the United States Virgin Islands, Guam, the Northern Mariana Islands, and American Samoa.

For purposes of subsection (b)(5)(C), *sophisticated concealment* means especially complex or especially intricate offense conduct in which deliberate steps are taken to make the offense, or its extent, difficult to detect. Conduct such as hiding assets or transactions, or both, through the use of fictitious entities, corporate shells, or offshore bank accounts ordinarily indicates sophisticated concealment.''.

The Commentary to § 2F1.1 captioned ''Application Notes'' is amended by adding at the end the following new note:

''20. *Mass-marketing,* as used in subsection (b)(7), means a plan, program, promotion, or campaign that is conducted through solicitation by telephone, mail, the Internet, or other means to induce a large number of persons to (A) purchase goods or services; (B) participate in a contest or sweepstakes; or (C) invest for financial profit. The enhancement would apply, for example, if the defendant conducted or participated in a telemarketing campaign that solicited a large number of individuals to purchase fraudulent life insurance policies.''.

Section 2T1.1(b) is amended by striking subdivision (2) in its entirety and inserting the following:

''(2) If the offense involved sophisticated concealment, increase by 2 levels.''.

The Commentary to § 2T1.1 captioned ''Application Notes'' is amended by striking Note 4 in its entirety and inserting the following:

''4. For purposes of subsection (b)(2), *sophisticated concealment* means especially complex or especially intricate offense conduct in which deliberate steps are taken to make the offense, or its extent, difficult to detect. Conduct such as hiding assets or transactions, or both, through the use of fictitious entities, corporate shells, or offshore bank accounts ordinarily indicates sophisticated concealment.''.

Section 2T1.4(b) is amended by striking subdivision (2) in its entirety and inserting the following:

''(2) If the offense involved sophisticated concealment, increase by 2 levels.''.

The Commentary to § 2T1.4 captioned ''Application Notes'' is amended by striking Note 3 in its entirety and inserting the following:

''3. For purposes of subsection (b)(1), *sophisticated concealment* means especially complex or especially intricate offense conduct in which deliberate steps are taken to make the offense, or its extent, difficult to detect. Conduct such as hiding assets or transactions, or both, through the use of fictitious entities, corporate shells, or offshore bank accounts ordinarily indicates sophisticated concealment.''.

Section 2T3.1(b) is amended by striking subdivision (1) in its entirety and inserting the following:

''(1) If the offense involved sophisticated concealment, increase by 2 levels.''.

The Commentary to § 2T3.1 captioned ''Application Notes'' is amended by adding at the end the following new note:

''3. For purposes of subsection (b)(1), *sophisticated concealment* means especially complex or especially intricate offense conduct in which deliberate steps are taken to make the offense, or its extent, difficult to detect. Conduct such as hiding assets or transactions, or both, through the use of fictitious entities, corporate shells, or offshore bank accounts ordinarily indicates sophisticated concealment.''.

Reason for Amendment: This amendment has three purposes: (1) to provide an increase for fraud offenses that use mass-marketing to carry out the fraud; (2) to provide an increase for fraud offenses that involve conduct, such as sophisticated concealment, that makes it difficult for law enforcement authorities to discover the offense or apprehend the offender; and (3) to clarify and conform an existing enhancement that provides an increase for tax offenses that similarly involve sophisticated concealment.

First, this amendment adds a two-level enhancement in the fraud guideline for offenses that are committed through mass-marketing. The Commission identified mass-marketing as a central component of telemarketing fraud and also determined that there were other fraudulent schemes that relied on mass-marketing to perpetrate the offense (for example, Internet fraud). Accordingly, rather than provide a limited enhancement for telemarketing fraud only, the Commission determined that a generally applicable specific offense characteristic in the fraud guideline would better provide consistent and proportionate sentencing increases for similar types of fraud, while also ensuring increased sentences for persons who engage in mass-marketed telemarketing fraud.

Second, this amendment provides an increase for fraud offenses that involve conduct, such as sophisticated concealment, that makes it difficult for law enforcement authorities to discover the offense or apprehend the offenders. The new enhancement provides a two-level increase and a ''floor'' offense level of level 12 in the fraud guideline and replaces the current enhancement for ''the use of foreign bank accounts or transactions to conceal the true nature or extent of fraudulent conduct.'' There are three alternative provisions to the enhancement. The first two prongs address conduct that the Commission

has been informed often relates to telemarketing fraud, although the conduct also may occur in connection with fraudulent schemes perpetrated by other means. Specifically, the Commission has been informed that fraudulent telemarketers increasingly are conducting their operations from Canada and other locations outside the United States. Additionally, testimony offered at a Commission hearing on telemarketing fraud indicated that telemarketers often relocate their schemes to other jurisdictions once they know or suspect that enforcement authorities have discovered the scheme. Both types of conduct are specifically covered by the new enhancement. The third prong provides an increase if any offense covered by the fraud guideline otherwise involves sophisticated concealment. This prong addresses cases in which deliberate steps are taken to make the offense, or its extent, difficult to detect.

Third, this amendment provides a two-level enhancement for conduct related to sophisticated concealment of a tax offense. The primary purpose of this amendment is to conform the language of the current enhancement for ''sophisticated means'' in the tax guidelines to the essentially equivalent language of the new sophisticated concealment enhancement provided in the fraud guideline. Additionally, the amendment resolves a circuit conflict regarding whether the enhancement applies based on the personal conduct of the defendant or the overall offense conduct for which the defendant is accountable. Consistent with the usual relevant conduct rules, application of this new enhancement for sophisticated concealment accordingly is based on the overall offense conduct for which the defendant is accountable.

3. *Amendment:* Section 2K2.1(a) is amended in subdivision (4) by striking ''the defendant'' after ''20, if''; in subdivision (4)(A) by inserting ''the defendant'' before ''had one''; in subdivision (4)(B) by striking ''is a prohibited person, and''; and in subdivision (4)(B) by inserting ''; and the defendant (i) is a prohibited person; or (ii) is convicted under 18 U.S.C. 922(d)'' after '' 921(a)(30)''.

Section 2K2.1(a)(6) is amended by inserting ''(A)'' after ''defendant''; and by inserting ''; or (B) is convicted under 18 U.S.C. 922(d)'' after ''person''.

The Commentary to § 2K2.1 captioned ''Application Notes'' is amended in Note 6 by striking ''or'' before ''(vi)''; and by inserting ''; or (vii) has been convicted in any court of a misdemeanor crime of domestic violence as defined in 18 U.S.C. 921(a)(33)'' after ''922(d)(8)''.

The Commentary to § 2K2.1 captioned ''Application Notes'' is amended in Note 12 in the first paragraph by striking ''924(j) or (k), or 26 U.S.C. 5861(g) or (h)'' and inserting ''924 (l) or (m)''; and in the second paragraph by striking ''only'' after ''if the''; and by inserting ''or 26 U.S.C. 5861(g) or (h)'' after ''922(k)''.

Reason for Amendment: This amendment has three purposes: (1) to change the definition of ''prohibited person'' in the firearms guideline so that it includes a person convicted of a misdemeanor crime of domestic violence; (2) to provide the same base offense levels for both a prohibited person and a person who is convicted under 18 U.S.C. 922(d) of transferring a firearm to a prohibited person; and (3) to make several technical and conforming changes to the firearms guideline.

The first part of the amendment amends Application Note 6 of § 2K2.1 (Unlawful Receipt, Possession, or Transportation of Firearms or Ammunition; Prohibited Transactions Involving Firearms or Ammunition) to include a person convicted of a misdemeanor crime of domestic violence within the scope of ''prohibited person'' for purposes of that guideline. It also defines ''misdemeanor crime of domestic violence'' by reference to the new statutory definition of that term in 18 U.S.C. 921(a).

This part of the amendment addresses section 658 of the Treasury, Postal Service, and General Government Appropriations Act, Pub. L. 104–208, 110 Stat. 3009 (1996) (contained in the Omnibus Consolidated Appropriations Act for Fiscal Year 1997). Section 658 amended 18 U.S.C. 922(d) to prohibit the sale of a firearm or ammunition to a person who has been convicted in any court of a misdemeanor crime of domestic violence. It also amended 18 U.S.C. 922(g) to prohibit a person who has been convicted in any court of a misdemeanor crime of domestic violence from transporting or receiving a firearm or ammunition. Section 922(s)(3)(B)(i), which lists the information a person not licensed under 18 U.S.C. 923 must include in a statement to the handgun importer, manufacturer, or dealer, was amended to require certification that the person to whom the gun is transferred was not convicted in any court of a misdemeanor crime of domestic violence. Section 658 also amended 18 U.S.C. 921(a) to define ''misdemeanor crime of domestic violence''.

Violations of 18 U.S.C. 922(d) and (g) are covered by § 2K2.1. The new provisions at § 922(d) (sale of a firearm to a ''prohibited person'') and § 922(g) (transporting, possession, and receipt of a firearm by a ''prohibited person'') affect Application Note 6 of § 2K2.1, which defines ''prohibited person''. This part of the amendment conforms Application Note 6 of § 2K2.1 to the new statutory provisions.

The second part of this amendment increases the base offense level for a defendant who is convicted under 18 U.S.C. 922(d), which prohibits the transfer of a firearm to a prohibited person. Specifically, this part amends the two alternative base offense levels that pertain to prohibited persons in the firearms guideline in order to make those offense levels applicable to the person who transfers the firearm to the prohibited person. A person who is convicted under 18 U.S.C. 922(d) has been shown beyond a reasonable doubt either to have known, or to have had reasonable cause to believe, that the transferee was a prohibited person.

This part of the amendment derives from a recommendation by the United States Department of Justice and is generally consistent with a proposed directive contained in juvenile justice legislation approved by the Senate Judiciary Committee in 1997.

The third part of this amendment makes two technical and conforming changes in Application Note 12 of § 2K2.1. First, the amendment corrects statutory references to 18 U.S.C. 924(j) and (k), which were added as a result of the Violent Crime Control and Law Enforcement Act of 1994, Pub. L. 103–322, 108 Stat. 1796 (1994). In the Economic Espionage Act of 1996, Pub. L. 104–294, 110 Stat. 3488 (1996), Congress again amended 18 U.S.C. 924 and redesignated the provisions as subsections (l) and (m). The amendment conforms Application Note 12 to that redesignation. Second, the amendment corrects the misplacement of the reference to 26 U.S.C. 5861(g) and (h).

4. *Amendment:* The Commentary to § 2J1.6 captioned ''Application Notes'' is amended in Note 3 in the first paragraph by striking ''3D1.2'' and inserting ''3D1.1''; and by striking the second paragraph in its entirety and inserting the following as the new second paragraph:

''In the case of a conviction on both the underlying offense and the failure to appear, the failure to appear is treated under § 3C1.1 (Obstructing or Impeding the Administration of Justice) as an obstruction of the underlying offense, and the failure to appear count and the count or counts for the underlying

offense are grouped together under § 3D1.2(c). (Note that 18 U.S.C. 3146(b)(2) does not require a sentence of imprisonment on a failure to appear count, although if a sentence of imprisonment on the failure to appear count is imposed, the statute requires that the sentence be imposed to run consecutively to any other sentence of imprisonment. Therefore, unlike a count in which the statute mandates both a minimum and a consecutive sentence of imprisonment, the grouping rules of §§ 3D1.1–3D1.5 apply. See § 3D1.1(b), comment. (n.1), and § 3D1.2, comment. (n.1).) The combined sentence will then be constructed to provide a 'total punishment' that satisfies the requirements both of § 5G1.2 (Sentencing on Multiple Counts of Conviction) and 18 U.S.C. 3146(b)(2). For example, if the combined applicable guideline range for both counts is 30–37 months and the court determines that a 'total punishment' of 36 months is appropriate, a sentence of 30 months for the underlying offense plus a consecutive six months' sentence for the failure to appear count would satisfy these requirements. (Note that the combination of this instruction and increasing the offense level for the obstructive, failure to appear conduct has the effect of ensuring an incremental, consecutive punishment for the failure to appear count, as required by 18 U.S.C. 3146(b)(2).)''.

The Commentary to § 2J1.6 captioned ''Application Notes'' is amended by redesignating Note 4 as Note 5; and by inserting the following as new Note 4:

''4. If a defendant is convicted of both the underlying offense and the failure to appear count, and the defendant committed additional acts of obstructive behavior (e.g., perjury) during the investigation, prosecution, or sentencing of the instant offense, an upward departure may be warranted. The upward departure will ensure an enhanced sentence for obstructive conduct for which no adjustment under § 3C1.1 (Obstruction of Justice) is made because of the operation of the rules set out in Application Note 3.''.

The Commentary to § 2P1.2 captioned ''Application Notes'' is amended in Note 2 by striking ''as amended,'' after ''18 U.S.C. 1791(c),''; and by inserting ''by the inmate'' after ''served''.

The Commentary to § 2P1.2 captioned ''Application Notes'' is amended in Note 2 by inserting before the first paragraph the following:

''In a case in which the defendant is convicted of the underlying offense and an offense involving providing or possessing a controlled substance in prison, group the offenses together under § 3D1.2(c). (Note that 18 U.S.C. 1791(b) does not require a sentence of imprisonment, although if a sentence of imprisonment is imposed on a count involving providing or possessing a controlled substance in prison, section 1791(c) requires that the sentence be imposed to run consecutively to any other sentence of imprisonment for the controlled substance. Therefore, unlike a count in which the statute mandates both a minimum and a consecutive sentence of imprisonment, the grouping rules of §§ 3D1.1–3D1.5 apply. See § 3D1.1(b), comment. (n.1), and § 3D1.2, comment. (n.1).) The combined sentence will then be constructed to provide a 'total punishment' that satisfies the requirements both of § 5G1.2 (Sentencing on Multiple Counts of Conviction) and 18 U.S.C. 1791(c). For example, if the combined applicable guideline range for both counts is 30–37 months and the court determines a 'total punishment' of 36 months is appropriate, a sentence of 30 months for the underlying offense plus a consecutive six months' sentence for the providing or possessing a controlled substance in prison count would satisfy these requirements.''.

The Commentary to § 3C1.1 captioned ''Application Notes'' is amended in Note 6 by striking ''Where'' and inserting ''If''; and by striking ''where'' both places it appears and inserting ''if''.

The Commentary to § 3C1.1 captioned ''Application Notes'' is amended in Note 7 in the first sentence by striking ''Where'' and inserting ''If''; by striking ''both of the'' and inserting ''both of an''; by inserting ''(e.g., 18 U.S.C. § 3146 (Penalty for failure to appear); 18 U.S.C. § 1621 (Perjury generally))'' after ''obstruction offense'' the first place it appears; and by striking ''the underlying'' the first place it appears and inserting ''an underlying''.

Section 3D1.1(b) is amended by striking the first sentence in its entirety and inserting the following:

''Exclude from the application of §§ 3D1.2–3D1.5 any count for which the statute (1) specifies a term of imprisonment to be imposed; and (2) requires that such term of imprisonment be imposed to run consecutively to any other term of imprisonment.''.

The Commentary to § 3D1.1 captioned ''Application Notes'' is amended by striking Note 1 in its entirety and inserting the following:

''1. Subsection (b) applies if a statute (A) specifies a term of imprisonment to be imposed; and (B) requires that such term of imprisonment be imposed to run consecutively to any other term of imprisonment. See, e.g., 18 U.S.C. 924(c) (requiring mandatory term of five years to run consecutively). The multiple count rules set out under this Part do not apply to a count of conviction covered by subsection (b). However, a count covered by subsection (b) may affect the offense level determination for other counts. For example, a defendant is convicted of one count of bank robbery (18 U.S.C. 2113), and one count of use of a firearm in the commission of a crime of violence (18 U.S.C. 924(c)). The two counts are not grouped together pursuant to this guideline, and, to avoid unwarranted double counting, the offense level for the bank robbery count under § 2B3.1 (Robbery) is computed without application of the enhancement for weapon possession or use as otherwise required by subsection (b)(2) of that guideline. Pursuant to 18 U.S.C. 924(c), the mandatory five-year sentence on the weapon-use count runs consecutively to the guideline sentence imposed on the bank robbery count. See § 5G1.2(a).

Unless specifically instructed, subsection (b) does not apply when imposing a sentence under a statute that requires the imposition of a consecutive term of imprisonment only if a term of imprisonment is imposed (i.e., the statute does not otherwise require a term of imprisonment to be imposed). See, e.g., 18 U.S.C. 3146 (Penalty for failure to appear); 18 U.S.C. 924(a)(4) (regarding penalty for 18 U.S.C. 922(q) (possession or discharge of a firearm in a school zone)); 18 U.S.C. 1791(c) (penalty for providing or possessing a controlled substance in prison). Accordingly, the multiple count rules set out under this Part do apply to a count of conviction under this type of statute.''.

The Commentary to § 3D1.2 captioned ''Application Notes'' is amended in Note 1 in the third sentence by striking ''mandates imposition of a consecutive sentence'' and inserting ''(A) specifies a term of imprisonment to be imposed; and (B) requires that such term of imprisonment be imposed to run consecutively to any other term of imprisonment''; and by inserting ''; id., comment. (n.1)'' after ''§ 3D1.1(b)''.

Section 5G1.2(a) is amended by striking ''mandates a consecutive sentence'' and inserting ''(1) specifies a term of imprisonment to be imposed; and (2) requires that such term of imprisonment be imposed to run consecutively to any other term of imprisonment''; and by inserting ''by that statute'' after ''determined''.

The Commentary to § 5G1.2 is amended in the last paragraph by striking the first three sentences and inserting:

''Subsection (a) applies if a statute (1) specifies a term of imprisonment to be imposed; and (2) requires that such term of imprisonment be imposed to run consecutively to any other term of imprisonment. See, e.g., 18 U.S.C. § 924(c) (requiring mandatory term of five years to run consecutively to any other term of imprisonment). The term of years to be imposed consecutively is determined by the statute of conviction, and is independent of a guideline sentence on any other count.''.

The Commentary to § 5G1.2 is amended in the last paragraph in the fourth sentence by inserting '', e.g.,'' after ''See''; and by adding at the end the following new sentence:

''Subsection (a) also applies in certain other instances in which an independently determined and consecutive sentence is required. See, e.g., Application Note 3 of the Commentary to § 2J1.6 (Failure to Appear by Defendant), relating to failure to appear for service of sentence.''.

Reason for Amendment: The purpose of this amendment is to clarify how several guideline provisions, including those on grouping multiple counts of conviction, work together to ensure an incremental, consecutive penalty for a failure to appear count. This amendment addresses a circuit conflict regarding whether the guideline procedure of grouping the failure to appear count of conviction with the count of conviction for the underlying offense violates the statutory mandate of imposing a consecutive sentence. *Compare United States* v. *Agoro,* 996 F.2d 1288 (1st Cir. 1993) (grouping rules apply), and *United States* v. *Flores,* No. 93–3771, 1994 WL 163766 (6th Cir. May 2, 1994) (unpublished) (same), with *United States* v. *Packer,* 70 F.3d 357 (5th Cir. 1995) (grouping rules defeat statutory purposes of 18 U.S.C. § 3146), cert. denied, 117 S. Ct. 75 (1996). The amendment maintains the current grouping rules for failure to appear and obstruction of justice, but addresses internal inconsistencies among different guidelines and explains how the guideline provisions work together to ensure an incremental, consecutive penalty for the failure to appear count. Specifically, the amendment (1) more clearly distinguishes between statutes that require imposition of a consecutive term of imprisonment only if imprisonment is imposed (e.g., 18 U.S.C. § 3146 (Penalty for failure to appear); 18 U.S.C. § 1791(b), (c) (Penalty for providing or possessing contraband in prison)), and statutes that require both a minimum term of imprisonment and a consecutive sentence (e.g., 18 U.S.C. § 924(c) (Use of a firearm in relation to crime of violence or drug trafficking offense)); (2) states that the method outlined for determining a sentence for failure to appear and similar statutes ensures an incremental, consecutive punishment; (3) adds an upward departure provision if offense conduct involves multiple obstructive acts; (4) makes conforming changes in § 2P1.2 (Providing or Possessing Contraband in Prison) because the relevant statute, 18 U.S.C. 1791, is similar to 18 U.S.C. 3146; and (5) makes conforming changes in §§ 3C1.1, 3D1.1, 3D1.2, and 5G1.2.

5. *Amendment:* The Commentary to § 3B1.3 captioned ''Application Notes'' is amended in the first paragraph of Note 1 in the third sentence by inserting ''public or private'' after ''position of''; in the fourth sentence by striking ''would apply'' and inserting ''applies''; and in the last sentence by striking ''would'' and inserting ''does.''.

The Commentary to § 3B1.3 captioned ''Application Notes'' is amended by redesignating Note 2 as Note 3; and by inserting the following as new Note 2:

''2. This enhancement also applies in a case in which the defendant provides sufficient indicia to the victim that the defendant legitimately holds a position of private or public trust when, in fact, the defendant does not. For example, the enhancement applies in the case of a defendant who (A) perpetrates a financial fraud by leading an investor to believe the defendant is a legitimate investment broker; or (B) perpetrates a fraud by representing falsely to a patient or employer that the defendant is a licensed physician. In making the misrepresentation, the defendant assumes a position of trust, relative to the victim, that provides the defendant with the same opportunity to commit a difficult-to-detect crime that the defendant would have had if the position were held legitimately.''.

The Commentary to § 3B1.3 captioned ''Background'' is amended by inserting after the first sentence the following:

''The adjustment also applies to persons who provide sufficient indicia to the victim that they legitimately hold a position of public or private trust when, in fact, they do not.''.

Reason for Amendment: The purpose of this amendment is to establish that the two-level increase for abuse of a position of trust applies to a defendant who is an imposter, as well as to a person who legitimately holds and abuses a position of trust. This amendment resolves a circuit conflict on that issue. Compare *United States* v. *Gill,* 99 F.3d 484 (1st Cir. 1996) (adjustment applied to defendant who posed as licensed psychologist), and *United States* v. *Queen,* 4 F.3d 925 (10th Cir. 1993) (adjustment applied to defendant who posed as financial broker), cert. denied, 510 U.S. 1182 (1994), with *United States* v. *Echevarria,* 33 F.3d 175 (2d Cir. 1994) (defendant who poses as physician does not occupy a position of trust). The amendment adopts the majority appellate view and provides that the abuse of position of trust adjustment applies to an imposter who pretends to hold a position of trust when in fact he does not. The Commission has determined that, particularly from the perspective of the crime victim, an imposter who falsely assumes and takes advantage of a position of trust is as culpable and deserving of increased punishment as is a defendant who abuses an actual position of trust.

6. *Amendment:* Section 3C1.1 is amended by inserting ''(A)'' after ''If''; by inserting ''the course of'' after ''during''; and by inserting ''of conviction, and (B) the obstructive conduct related to (i) the defendant's offense of conviction and any relevant conduct; or (ii) a closely related offense'' after ''instant offense''.

The Commentary to § 3C1.1 captioned ''Application Notes'' is amended in Note 2 in the second sentence by striking ''Note 3'' and inserting ''Note 4''; in the third sentence by striking ''Note 4'' and inserting ''Note 5''; and in the fourth sentence by striking ''Notes 3 and 4'' and inserting ''Notes 4 and 5''.

The Commentary to § 3C1.1 captioned ''Application Notes'' is amended in Note 4 in the first paragraph by striking ''Note 7'' and inserting ''Note 8''.

The Commentary to § 3C1.1 captioned ''Application Notes'' is amended by redesignating Notes 1 through 8, as Notes 2 through 9, respectively; and by inserting the following as new Note 1:

''1. This adjustment applies if the defendant's obstructive conduct (A) occurred during the course of the investigation, prosecution, or sentencing of the defendant's instant offense of conviction, and (B) related to (i) the defendant's offense of conviction and any relevant conduct; or (ii) an otherwise closely related case, such as that of a co-defendant.''.

Reason for Amendment: The purpose of this amendment is to clarify what the term *instant offense* means in the obstruction of justice guideline, § 3C1.1. This amendment resolves a circuit conflict on the issue of whether the adjustment applies to obstructions that occur in cases closely related to the defendant's case or only those specifically related to the offense of which the defendant convicted. Compare *United States* v. *Powell,* 113

F.3d 464 (3d Cir.) (adjustment applies if defendant attempts to impede the prosecution of a co-defendant who is charged with the same offense for which defendant was convicted), cert. denied, 118 S. Ct. 454 (1997), *United States* v. *Walker*, 119 F.3d 403 (6th Cir.) (same), cert. denied, 118 S. Ct. 643 (1997), *United States* v. *Acuna*, 9 F.3d 1442 (9th Cir. 1993) (adjustment applies if defendant attempts to obstruct justice in a case closely related to his own), and *United States* v. *Bernaugh*, 969 F.2d 858 (10th Cir. 1992) (adjustment applies when defendant testifies falsely at his own hearing about co-defendants' roles in the offense), with *United States* v. *Perdomo*, 927 F.2d 111 (2d Cir. 1991) (cannot apply adjustment based on obstructive conduct outside the scope of charged offense), and *United States* v. *Partee*, 31 F.3d 529 (7th Cir. 1994) (same). The amendment, which adopts the majority view, instructs that the obstruction must relate either to the defendant's offense of conviction (including any relevant conduct) or to a closely related case. The amendment also clarifies the temporal element of the obstruction guideline (i.e., that the obstructive conduct must occur during the investigation, prosecution, or sentencing of the defendant's offense of conviction).

7. Amendment: The Commentary to § 3C1.1 captioned ''Application Notes'' is amended in Note 4 in the first sentence of the first paragraph by striking ''enhancement'' and inserting ''adjustment''; and by inserting ''or affect the determination of whether other guideline adjustments apply (e.g., § 3E1.1 (Acceptance of Responsibility))'' after ''guideline range''; in the second sentence by striking ''enhancement'' and inserting ''adjustment''; in subdivision (d) by striking the period at the end and inserting a semicolon; and by adding at the end the following new subdivision:

''(e) lying to a probation or pretrial services officer about defendant's drug use while on pre-trial release, although such conduct may be a factor in determining whether to reduce the defendant's sentence under § 3E1.1 (Acceptance of Responsibility).''.

Reason for Amendment: The purpose of this amendment is to establish that lying to a probation officer about drug use while released on bail does not warrant an obstruction of justice adjustment under § 3C1.1. This amendment resolves a circuit conflict on that issue. Compare *United States* v. *Belletiere*, 971 F.2d 961 (3d Cir. 1992) (lying about drug use is not obstructive conduct that impedes government's investigation of instant offense), and *United States* v. *Thompson*, 944 F.2d 1331 (7th Cir. 1991) (same), cert. denied, 502 U.S. 1097 (1992), with *United States* v. *Garcia*, 20 F.3d 670 (6th Cir. 1994) (falsely denying drug use, while not outcome-determinative, is relevant), cert. denied, 513 U.S. 1159 (1995). The amendment, which adopts the majority view, excludes from application of § 3C1.1 a defendant's denial of drug use while on pre-trial release, although the amendment provides that such conduct may be relevant in determining the application of other guidelines, such as § 3E1.1 (Acceptance of Responsibility).

8. *Amendment:* Section 5K2.13 is amended by striking the text in its entirety and inserting:

''A sentence below the applicable guideline range may be warranted if the defendant committed the offense while suffering from a significantly reduced mental capacity. However, the court may not depart below the applicable guideline range if (1) the significantly reduced mental capacity was caused by the voluntary use of drugs or other intoxicants; (2) the facts and circumstances of the defendant's offense indicate a need to protect the public because the offense involved actual violence or a serious threat of violence; or (3) the defendant's criminal history indicates a need to incarcerate the defendant to protect the public. If a departure is warranted, the extent of the departure should reflect the extent to which the reduced mental capacity contributed to the commission of the offense.

Commentary

Application Note:

1. For purposes of this policy statement—

Significantly reduced mental capacity means the defendant, although convicted, has a significantly impaired ability to (A) understand the wrongfulness of the behavior comprising the offense or to exercise the power of reason; or (B) control behavior that the defendant knows is wrongful.''.

Reason for Amendment: The purpose of this amendment is to allow (except under certain circumstances) a diminished capacity departure if there is sufficient evidence that the defendant committed the offense while suffering from a significantly reduced mental capacity. This amendment addresses a circuit conflict regarding whether the diminished capacity departure is precluded if the defendant committed a ''crime of violence'' as that term is defined in the career offender guideline. Compare *United States* v. *Poff*, 926 F.2d 588 (7th Cir.) (en banc) (definition of ''non-violent offense'' necessarily excludes a crime of violence), cert. denied, 502 U.S. 827 (1991), *United States* v. *Maddalena*, 893 F.2d 815 (6th Cir. 1989) (same), *United States* v. *Mayotte*, 76 F.3d 887 (8th Cir. 1996) (same), *United States* v. *Borrayo*, 898 F.2d 91 (9th Cir. 1989) (same), and *United States* v. *Dailey*, 24 F.3d 1323 (11th Cir. 1994) (same), with *United States* v. *Chatman*, 986 F.2d 1446 (D.C. Cir. 1993) (court must consider all the facts and circumstances to determine whether offense was non-violent; terms are not mutually exclusive), *United States* v. *Weddle*, 30 F.3d 532 (4th Cir. 1994) (same), and *United States* v. *Askari*, F.3d, 1998 WL 164561 (3d Cir. 1998) (en banc) (''non-violent offenses'' are those that do not involve a reasonable perception that force against persons may be used in committing the offense), abrogating *United States* v. *Rosen*, 896 F.2d 789 (3d Cir. 1990) (non-violent offense means the opposite of crime of violence). The amendment replaces the current policy statement with a new provision that essentially represents a compromise approach to the circuit conflict. The new policy statement allows a diminished capacity departure if there is sufficient evidence that the defendant committed the offense while suffering from a significantly reduced mental capacity, except under the following three circumstances: (1) the significantly reduced mental capacity was caused by the voluntary use of drugs or other intoxicants; (2) the facts and circumstances of the defendant's offense indicate a need to protect the public because the offense involved actual violence or a serious threat of violence; or (3) the defendant's criminal history indicates a need to incarcerate the defendant to protect the public. The amendment also adds an application note that defines ''significantly reduced mental capacity'' in accord with the decision in *United States* v. *McBroom*, 124 F.3d 533 (3d Cir. 1997). The McBroom court concluded that ''significantly reduced mental capacity'' included both cognitive impairments (i.e., an inability to understand the wrongfulness of the conduct or to exercise the power of reason) and volitional impairments (i.e., an inability to control behavior that the person knows is wrongful). The application note specifically includes both types of impairments in the definition of ''significantly reduced mental capacity''.

9. *Amendment:* Section 5B1.3(d) is amended by adding at the end the following new subdivision:

''(6) Deportation

If (A) the defendant and the United States entered into a stipulation of

deportation pursuant to section 238(c)(5) of the Immigration and Nationality Act (8 U.S.C. § 1228(c)(5)); or (B) in the absence of a stipulation of deportation, if, after notice and hearing pursuant to such section, the Attorney General demonstrates by clear and convincing evidence that the alien is deportable—a condition ordering deportation by a United States district court or a United States magistrate judge.''.

Section 5D1.3(d) is amended by adding at the end the following new subdivision:

''(6) Deportation

If (A) the defendant and the United States entered into a stipulation of deportation pursuant to section 238(c)(5) of the Immigration and Nationality Act (8 U.S.C. § 1228(c)(5)); or (B) in the absence of a stipulation of deportation, if, after notice and hearing pursuant to such section, the Attorney General demonstrates by clear and convincing evidence that the alien is deportable—a condition ordering deportation by a United States district court or a United States magistrate judge.''.

Section 5D1.3(e)(5) is amended by striking ''to provide just punishment for the offense,''.

Section 5B1.3(c) is amended by inserting ''(Policy Statement)'' before ''The following''.

Section 5B1.3(d) is amended by inserting ''(Policy Statement)'' before ''The following''.

Section 5B1.3(e) is amended in the title by adding ''(Policy Statement)'' at the end.

Section 5D1.3(c) is amended by inserting ''(Policy Statement)'' before ''The following''.

Section 5D1.3(d) is amended by inserting ''(Policy Statement)'' before ''The following''.

Section 5D1.3(e) is amended in the title by adding ''(Policy Statement)'' at the end.

Reason for Amendment: The purpose of this amendment is to make several technical and conforming changes to the guidelines relating to conditions of probation and supervised release. The amendment has three parts. First, the amendment adds to § 5B1.3 a condition of probation regarding deportation, in response to section 374 of the Illegal Immigration Reform and Immigrant Responsibility Act of 1996, Pub. L 104–208, 110 Stat. 3009 (1996). That section amended 18 U.S.C. § 3563(b) to add a new discretionary condition of probation with respect to deportation. Second, this amendment deletes the reference in the supervised release guideline to ''just punishment'' as a reason for the imposition of curfew as a condition of supervised release. The need to provide ''just punishment'' is not included in 18 U.S.C. § 3583(c) as a permissible factor to be considered in imposing a term of supervised release. Third, this amendment amends the guidelines pertaining to conditions of probation and supervised release to indicate that discretionary (as opposed to mandatory) conditions are advisory policy statements of the Commission, not binding guidelines.

10. *Amendment:* Section 5K2.0 is amended in the first paragraph in the first sentence by inserting a comma after ''3553(b)''; by striking ''guideline'' and inserting ''guidelines''; in the second sentence by striking ''guidelines'' and inserting ''guideline range''; in the third sentence by striking ''controlling'' after ''The''; by striking ''can only be made by the courts'' and inserting ''rests with the sentencing court on a case-specific basis''; in the last sentence by inserting ''determining'' after ''consideration in''; by striking ''guidelines'' and inserting ''guideline range''; by striking ''guideline level'' and inserting ''weight''; by inserting ''under the guidelines'' after ''factor''; and by inserting before the period at the end ''or excessive''.

Section 5K2.0 is amended in the last paragraph by striking ''An'' and inserting ''Finally, an''; by striking ''not ordinarily relevant'' and inserting '', in the Commission's view, 'not ordinarily relevant' ''; and by striking ''in a way that is important to the statutory purposes of sentencing''.

The Commentary to § 5K2.0 is amended by inserting before the first paragraph the following:

''The United States Supreme Court has determined that, in reviewing a district court's decision to depart from the guidelines, appellate courts are to apply an abuse of discretion standard, because the decision to depart embodies the traditional exercise of discretion by the sentencing court. *Koon* v. *United States,* 116 S. Ct. 2035 (1996). Furthermore, '[b]efore a departure is permitted, certain aspects of the case must be found unusual enough for it to fall outside the heartland of cases in the Guideline. To resolve this question, the district court must make a refined assessment of the many facts bearing on the outcome, informed by its vantage point and day-to-day experience in criminal sentencing. Whether a given factor is present to a degree not adequately considered by the Commission, or whether a discouraged factor nonetheless justifies departure because it is present in some unusual or exceptional way, are matters determined in large part by comparison with the facts of other Guidelines cases. District Courts have an institutional advantage over appellate courts in making these sorts of determinations, especially as they see so many more Guidelines cases than appellate courts do.' Id. at 2046–47.''.

Reason for Amendment: The purpose of this amendment is to reference specifically in the general departure policy statement the United States Supreme Court's decision in *United States* v. *Koon,* 116 S. Ct. 2035 (1996). This amendment (1) incorporates the principal holding and key analytical points from the Koon decision into the general departure policy statement, § 5K2.0; (2) deletes language inconsistent with the holding of Koon; and (3) makes minor, non-substantive changes that improve the precision of the language of § 5K2.0.

11. *Amendment:* Section 2B3.2(b) is amended in subdivision (2) by striking ''(b)(6)'' and inserting ''(b)(7)''.

The Commentary to § 2K2.1 captioned ''Application Notes'' is amended in Note 5 in the first sentence by striking ''subsections (1) and (2)'' and inserting ''subsections (a)(1), (a)(2), and (b)''.

The Commentary to § 6A1.3 is amended in the third paragraph by striking ''117 U.S.'' after ''Watts,'' both places it appears and inserting ''117 S. Ct.''.

Reason for Amendment: This amendment corrects technical errors in §§ 2B3.1, 2K2.1, and 6A1.3.

Part II—Proposed Amendment in Response to the No Electronic Theft Act of 1997

Synopsis of Proposed Amendment: In section 2(g) of the No Electronic Theft Act of 1997, Pub. L. 105B147, Congress directed the Commission to (1) ''ensure that the applicable guideline range for a defendant convicted of a crime against intellectual property (including offenses set forth at section 506(a) of title 17, United States Code, and sections 2319, 2319A, and 2329 of title 18, United States Code) is sufficiently stringent to deter such a crime and to adequately reflect the additional considerations set forth in paragraph (2)''; and (2) ''ensure that the guidelines provide for consideration of the retail value and quantity of the items with respect to which the crime against intellectual property was committed.''

Three possible approaches for implementing these directives are set forth below. Option One is the result of the Commission's review and consideration of the directives, after taking into account pertinent hearing testimony, written public comment, and

other input of interested parties. Upon the Commission's request for input from the Department of Justice, the Department proposed Options Two and Three as possible approaches for carrying out the statutory directives. The Commission invites comment on each of these three proposals, as well as any other comment on how the congressional directives might best be implemented. Additionally, the Commission invites comment on whether the Commission can and should promulgate any of these proposed amendments (or any other amendments to the guidelines, policy statements, and official commentary to carry out these directives) pursuant to the emergency amendment authority of section 21 of the Sentencing Act of 1987.

Note: Persons commenting on this issue may wish to consider whether the authority of the Commission to adopt emergency amendments to the guidelines in order to implement the directives is sufficiently clear inasmuch as the authority to act on an emergency basis under section 21 of the Sentencing Act of 1987, which was cited in section 2(g) of the No Electronic Theft Act of 1997, has expired and may not have been revived adequately by that section.

Proposed Amendment:

Option One [Commission Proposal]:

Strike § 2B5.3 and insert the following:

§ 2B5.3. Criminal Infringement of Copyright or Trademark

(a) Base Offense Level: 6

(b) Specific Offense Characteristics

(1) If (A) the offense involved (i) the infringement of a copyright other than a copyright violation under 18 U.S.C. 2319A, (ii) the infringement of both a copyright and a trademark, or (iii) palmed-off counterfeit goods; and (B) the infringed value exceeded $2,000, increase by the number of levels from the monetary table in § 2F1.1 (Fraud and Deceit) corresponding to that value.

(2) If (A) subsection (b)(1) does not apply; and (B) the infringing value exceeded $2,000, increase by the number of levels from the monetary table in § 2F1.1 corresponding to that value.

[(3) If the offense involved online electronic infringement, increase by 2 levels.]

[(4) If the offense was not committed for commercial advantage or private financial gain, decrease by [2] levels, but not below level 6.]

[(5) If the offense involved the conscious or reckless risk of serious bodily injury or death, increase by [2] levels. If the resulting offense level is less than level [13][14], increase to level [13][14]].

Commentary

Application Notes:

1. For purposes of this guideline—

Infringed value means the average retail value of the infringed-upon item multiplied by the number of infringing items. *Infringed-upon item* means the legitimate item with respect to which or against which the crime against intellectual property was committed. *Average retail value of the infringed-upon item* generally means the average price that a well-informed consumer typically would pay for the legitimate item (which may be less than the Manufacturer's Suggested Retail Price). In cases involving the interception of a communication in violation of 18 U.S.C. § 2511, the *average retail value of the infringed-upon item* means the price the user would have paid if that communication had been obtained lawfully.

Infringing value means the average retail value of the infringing item multiplied by the number of infringing items.

Infringing item means the item that violates the copyright or trademark laws.

Palmed-off counterfeit goods means counterfeit goods that a consumer reasonably would believe are the legitimate items, because of price comparability and apparent substitutability.

Online electronic infringement includes the unlawful producing, reproducing, distributing, selling, performing, or trafficking in copyrighted or trademarked articles or services via an electronic bulletin board, a worldwide web site, or any online facility.

Commercial advantage or private financial gain includes receipt, or expectation of receipt, of anything of value, including the receipt of other protected works.

2. The enhancement in subsection (b)(2) applies to any infringement case not covered by subsection (b)(1) and in which the infringing value exceeded $2,000. The types of cases to which subsection (b)(2) is intended to apply include, for example, most cases involving trademark infringement, as well as cases involving the unlawful recording of a musical performance in violation of 18 U.S.C. § 2319A.

3. There may be cases in which the offense level substantially understates or overstates the seriousness of the offense or the culpability of the defendant. In such cases, an upward or downward departure, as appropriate, may be warranted.

Background: This guideline treats copyright and trademark violations much like fraud. The enhancements in subsections (b)(1) and (2) are intended as an approximate determination of the aggregate pecuniary harm resulting from trafficking in goods or services that violate the copyright or trademark laws.

The Electronic Communications Privacy Act of 1986 prohibits the interception of satellite transmission for purposes of direct or indirect commercial advantage or private financial gain. Such violations are similar to copyright offenses and are therefore covered by this guideline.''.

Option Two [Department of Justice Proposal]:

Strike § 2B5.3 and insert the following:

''§ 2B5.3. Criminal Infringement of Copyright or Trademark

(a) Base Offense Level: 6

(b) Specific Offense Characteristics

(1) If the economic harm exceeded $2,000, increase by the corresponding number of levels from the table in § 2F 1.1 (Fraud and Deceit).

(2) If the offense involved online electronic infringement, increase by 2 levels.

(3) If the offense posed a threat to public health and safety, increase by 2 levels.

Commentary

Statutory Provisions: 17 U.S.C. § 506(a); 18 U.S.C. 2318, 2319, 2319A, 2320, 2511. For additional statutory provision(s), see Appendix A (Statutory Index).

Application Notes:

1. For purposes of this guideline—

Infringed upon items means the items (including phonorecords and computer programs) with respect to which or against which the crime against intellectual property was committed.

Infringing items means the items that violate the copyright or trademark laws; often, infringing trademarks, and the items bearing them, are referred to as *counterfeit* and items that infringe copyrights are referred to as *pirated*.

Retail value means the Manufacturer's Suggested Retail Price (MSRP).

Copies means both copies and phonorecords.

Trafficked in includes transported, transferred, distributed, sold or otherwise disposed of.

2. *Economic harm* in 2318, 2319 (506(a)), and 2320 cases is the retail value of the infringed upon items, multiplied by the number of copies produced and trafficked in. This recognizes that infringement causes losses not only for the trademark and copyright owners, but for others in the distribution chains of legitimate articles, and for members of the public who are

deceived into buying what they may believe are legitimate articles.

A single copy that is produced and then sold by a single defendant counts as one copy.

3. *Economic harm* in 2319A cases is the retail value of the infringing items, multiplied by the number of copies produced (including the number of primary unlawful fixations, i.e., 'masters,' from which those copies are made) and/or transmissions and/or the number of copies sold, offered for sale, distributed, offered for distribution, rented, offered for rent, and trafficked in. The value of infringing items is the standard in these cases because merchandise that violates § 2319A has no legitimate counterpart. A single copy that is produced and then sold by a single defendant counts as one copy.

4. *Online electronic infringement* includes the producing, reproducing, distributing, selling, performing, or trafficking in copyrighted or trademarked articles or services via an electronic bulletin board, a worldwide web site, or any online *facility.* The ease with which infringers can operate in the online environment and the access they have to limitless numbers of customers gives them the capability of causing substantial harm. For example, a defendant may post copyrighted material to an electronic bulletin board, making it accessible for others to illegally obtain, copy, and further distribute. In such an instance, it may not be possible to determine precisely the number of items (copies) downloaded by persons who access the facility, but it is reasonable to assure, based on the worldwide possibility for distribution and the number of items offered at the facility, that the harm is substantial.

5. In many instances, items that violate the trademark and copyright laws also present public health and safety hazards. These hazards can appear in many contexts. For example, counterfeit products, such as automotive parts, airplane parts, foodstuffs, pharmaceuticals, and electrical devices, place members of the public in danger. The enhancement shall apply in cases in which the products, if used in their intended manner, would threaten public health and safety.

6. An upward departure may be warranted in cases in which the economic harm underrepresents the actual harm or would lead to an unfair result. This Application Note applies in infringement situations, other than those referred to in Application Note 4, in which the number of copies produced and trafficked in is impossible to calculate and the harm to the copyright or trademark owner, others in the legitimate distribution chains, and the public is substantial. For example, rather than operate as an individual, a defendant may be part of a distribution or manufacturing network in which he or she supplies other distributors with unlawful products or parts of products, such as counterfeit handbags or watches or their parts or pirated sound recordings or motion pictures. In such an instance, it may not be possible to determine precisely the number of items (copies) provided to other persons for distribution, but it is reasonable, based on the available facts (including the number of persons in the distribution network), that the number is large enough to create substantial harm. The upward departure provided for in this Application Note is available regardless of whether the conduct was for financial gain.

7. A downward departure may be warranted in cases in which the retail price of the infringing items is less than 30% of the retail value of the infringed upon item. In such cases, it may not be reasonable to conclude that each sale of an infringing item represents a lost sale for the copyright or trademark owner or others in the distribution chain. For example, a counterfeit watch may retail for $15, while the infringed upon watch may retail for $5,000. A sentencing calculation based on the retail value of the infringed items may lead to an unfair result.

Background: This guideline treats copyright and trademark violations much like fraud.

The Electronic Communications Privacy Act of 1986 prohibits the interception of satellite transmission for purposes of direct or indirect commercial advantage or private financial gain. Such violations are similar to copyright offenses and are, therefore, covered by this guideline.''.

Option Three [Department of Justice Proposal]:

Strike § 2B5.3 and insert the following:

§ 2B5.3. Criminal Infringement of Copyright or Trademark

(a) Base Offense Level: 6

(b) Specific Offense Characteristics

(1) If the economic harm exceeded $2,000, increase by the corresponding number of levels from the table in § 2F1.1 (Fraud and Deceit).

(2) If the offense involved online electronic infringement, increase by 2 levels.

(3) If the retail price of the infringing items is less than 50% of the manufacturer's suggested retail price of the infringed upon items, decrease by 2 levels; if the retail price of the infringing items is less than 30% of the manufacturer's suggested retail price of the infringed upon items, decrease by 4 levels.

Commentary

Statutory Provisions: 17 U.S.C. § 506(a), 18 U. S. C. 2318, 2319, 2319A, 2320, 2511. For additional statutory provision(s), see Appendix A (Statutory Index).

Application Notes:

1. For purposes of this guideline

Infringed upon items means the legitimate items (including phonorecords and computer programs) with respect to which or against which the crime against intellectual property was committed.

Infringing items means the items that violate the copyright or trademark laws; often, infringing trademarks, and the items bearing them, are referred to as *counterfeit* and items that infringe copyrights are referred to as *pirated.*

Copies means both copies and phonorecords.

2. *Economic harm* in section 2318, 2319 (506(a)), and 2320 cases is the manufacturer's suggested retail price (msrp) of the infringed upon items, multiplied by the number of copies involved in the offense. This recognizes that the economic harm caused by infringement affects not only the trademark and copyright owners, but also others in the distribution chains of legitimate articles, and members of the public who are deceived into buying what they may believe are legitimate articles.

Because there is no infringed upon item in section 2319A cases, 'economic harm' in those cases is the retail price of the infringing items, multiplied by the number of copies involved in the offense (including the number of primary unlawful recordings, i.e., 'masters,' from which those copies are made).

Economic harm in section 2511 caves is the price the user or users would have paid if the service had been obtained lawfully.

3. *Online electronic infringement* includes the producing, reproducing, distributing, selling, performing, or trafficking in copyrighted or trademarked articles or services via an electronic bulletin board, a worldwide web site, or any online *facility.* The ease with which infringers can operate in the online environment and the access they have to limitless numbers of customers gives them the capability of causing substantial harm.

4. An upward departure may he warranted in cases in which the unlawful conduct presents a reasonably

foreseeable risk to public health or safety. These hazards appear in many contexts. For example, counterfeit products, such as automotive parts, airplane parts, foodstuffs, pharmaceuticals, and electrical devices, place members of the public in danger.

5. An upward departure may be warranted in cases in which the standard calculation of economic harm under-represents the actual harm or would lead to an unfair result. This Application Note applies in infringement situations, other than those referred to in Application Note 3, in which the number of copies involved in the offense is impossible to calculate and the harm to the copyright or trademark owner, others in the legitimate distribution chain, and the public is substantial. For example, rather that operate as an individual, a defendant may be part of a distribution or manufacturing network in which he or she supplies other distributors with unlawful products or parts of products, such as counterfeit handbags or watches or their parts or pirated sound recordings or motion pictures or their packaging, In such cases, it may not be possible to determine precisely the number of items (copies) provided to other persons for distribution, but it is reasonable, based on the available facts (including the number of persons in the distribution network), that the number is large enough to create substantial harm. The upward departure provided for in this Application Note is available regardless of whether the conduct was for commercial advantage or financial gain.

Background: This guideline treats copyright and trademark violations much like fraud.

The Electronic Communications Privacy Act of 1986 prohibits the interception of satellite transmission for purposes of direct or indirect commercial advantage or private financial gain. Such violations are similar to copyright offenses and are, therefore, covered by this guideline.''.

[FR Doc. 98–13584 Filed 5–20–98; 8:45 am]

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federal register

Thursday
May 21, 1998

Part IV

Department of Housing and Urban Development

Notice and Request for Comments on HUD's Implementation of the Small Business Regulatory Enforcement Fairness Act of 1996; Notice

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–4347–N–01]

Notice and Request for Comments on HUD's Implementation of the Small Business Regulatory Enforcement Fairness Act of 1996

AGENCY: Office of the Secretary, HUD.

ACTION: Notice.

SUMMARY: This notice solicits comments on HUD's implementation of the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). The notice describes HUD's implementation to date of SBREFA and additional implementation plans.

DATES: COMMENT DUE DATE: July 20, 1998.

ADDRESSES: Interested persons are invited to submit comments regarding this document to the Regulations Division, Office of the General Counsel, Room 10276, Department of Housing and Urban Development, 451 Seventh Street, SW, Washington, DC 20410–0500. Communications should refer to the above docket number and title and to the specific sections in the regulation. Facsimile (FAX) comments are not acceptable. A copy of each communication submitted will be available for public inspection and copying during regular business hours at the above address.

FOR FURTHER INFORMATION CONTACT: Casimir Bonkowski, Director, Office of Small and Disadvantaged Businesses, Department of Housing and Urban Development, Room 3130 451 Seventh Street, S.W., Washington, DC 20410, telephone 202–708–1428. Hearing- or speech-impaired persons may use the telecommunications system for the hearing-impaired (TTY) by contacting the Federal Information Relay Service on 1–800–877-TTY (1–800–877–8339) or (202) 708–9300. (Other than the ''800'' TTY number, telephone numbers are not toll-free.)

SUPPLEMENTARY INFORMATION:

I. The Small Business Regulatory Enforcement Fairness Act

The Small Business Regulatory Enforcement Fairness Act of 1996 (Pub.L. 104–121, 110 Stat. 847, approved March 29, 1996) (''SBREFA'') provides, among other things, for agencies to establish specific policies or programs to assist small entities. Small entities include small businesses, nonprofit organizations, and small governmental jurisdictions.

Section 213 of SBREFA requires each covered agency to establish a program to answer inquiries concerning information and advice about compliance with statutes and regulations within the agency's jurisdiction. The agency must use information received during these inquiries to help small entities interpret and apply the regulations to specific facts.

Section 223 of SBREFA requires each covered agency to establish a policy or program to reduce or waive civil penalties when a small entity violates a statute or regulation. Under appropriate circumstances, an agency may consider ability to pay when it assesses a penalty against a small entity. [1]

II. Identification of HUD Regulations That May Have a Significant Economic Impact on a Substantial Number of Small Entities

Although HUD is not generally regarded as a ''regulatory agency'', HUD has important regulatory responsibilities, including oversight and enforcement of the Real Estate Settlement Procedures Act (RESPA) and the Interstate Land Sales Full Disclosure Act; oversight over certain activities of government-sponsored enterprises (GSEs); oversight and enforcement of FHA mortgage insurance programs; and the establishment and enforcement of lead-based paint hazard control standards and manufactured housing standards.

HUD has long had in place a systematic process for determining whether newly developed rules are likely to have a significant economic impact on a substantial number of small entities. The typical HUD rule implements statutory directions for the administration of grant programs. Rules of this type are intended to reflect Congressional mandates that, by their nature, have universal applicability to the portion of the public affected by the rule. These rules generally do not lend themselves to the provision of special procedures, or exemptions from requirements, applicable to small entities. Although HUD Rules are generally not the type to lend themselves to special procedures or exemptions for small entities, HUD nevertheless has developed a process intended to introduce additional scrutiny to existing procedures for safeguarding the interests of small entities during development and following implementation of regulations.

To ensure that there is a meaningful assessment of HUD rules to determine which rules, if any, will have a significant economic impact on substantial number of small businesses, HUD:

(1) Targets regulations that may impact small businesses at the earliest opportunity in the development process; and

(2) Assigns oversight responsibility to HUD's Office of Small and Disadvantaged Business Utilization (OSDBU) to review:

(i) the HUD program office's assessment of any significant economic impact on a substantial number of small entities;

(ii) the HUD program office's assessment and disposition of all alternative rule implementation strategies submitted by small entities, and

(iii) the small entity compliance guides prepared by the program offices, where applicable.

III. Guidance to Small Entities

To help small entities understand their obligations under the regulations administered by HUD, HUD provides both general guidance and individualized advice. OSDBU maintains the requirements of the SBREFA and Regulatory Flexibility Act on the HUD web site with instructions to small entities on the OSDBU role as small business Ombudsman, as well as copies of compliance guides, names of HUD staff with familiarity in HUD programs that may impact small businesses, to answer questions, and a users forum where representatives of small entities can ask questions on a specific rule as a means of providing a fast means of clarifying issues. Additionally, small entities can download regulations, forms, and documentation from the HUD web pages. If a small entity does not have access to a computer, HUD will mail this information on request.

To ensure that we evaluate and update our small entity assistance program periodically, HUD works with the Small Business Administration to identify small business concerns in the housing industry.

IV. Rights of Small Entities in Enforcement Actions

Section 223 of SBREFA requires agencies that regulate the activities of small entities to establish a policy or program to reduce or, under appropriate circumstances, waive civil penalties when a small entity violates a statute or

[1] The applicable procurement statutes and regulations do not provide for special consideration of or rights for small governmental entities. SBREFA did not make statutory changes that would result in changes to the Federal Acquisition Regulation to address small entities.

regulation. (For purposes of brevity, this policy or program is referred to as the ''small entity compliance policy.'')

Section 223 also requires an agency's small entity compliance policy to contain conditions or exclusions (subject to any restrictions or limitations that may be imposed on the agency by other statutes), which conditions or exclusions may include, but are not limited to the following:

(1) Requiring small entities to correct the violation within a reasonable correction period;

(2) Limiting applicability of the small entity compliance policy to violations discovered when small entities participate in a compliance assistance or audit program operated by the agency;

(3) Excluding from applicability of the small entity compliance policy those small entities that have been subject to multiple enforcement actions by the agency;

(4) Excluding from applicability of the small entity compliance policy violations involving willful or criminal conduct or that pose serious health, safety, or environmental threats, safety, or requiring a good-faith effort to comply with the law.

Federal statutes and regulations authorize HUD to impose civil penalties in conjunction with regulatory and enforcement issues. Under these authorities, HUD has authority to issue civil money penalties for violations of requirements governing its grant, mortgage insurance, and the regulatory programs, identified earlier in this notice.

In establishing its policy for implementation of SBREFA, following enactment of SBREFA, HUD reported to President Clinton and the Congress that, under appropriate circumstances, HUD may consider ability to pay in determining penalty assessments on small entities. HUD notes that the ability to pay is a legislative directive for many programs under the Department of Housing and Urban Development Reform Act of 1989 (Pub. L. 101–235, approved December 15, 1989). HUD's policy to date has been to assist regulated entities in achieving compliance with requirements in order to avoid any penalty process.

Where penalties are determined appropriate, HUD's policy is to consider: (1) the nature of the violation (the violation must not be one that is repeated or multiple, willful, criminal or poses health or safety risks), (2) whether the entity has shown a good faith effort to comply with the regulations; and (3) the resources of the regulated entity. Depending upon the circumstances surrounding the violation, it is not HUD's intent to put any individual or entity out of business by the penalties or settlement amounts paid to the Federal Government.

V. Small Entities' Comments on Agencies Enforcement Activities

Section 222 of SBREFA requires the Small Business and Agriculture Regulatory Enforcement Ombudsman to ''work with each agency with regulatory authority over small businesses to ensure that small business concerns that receive or are subject to an audit, on-site inspection, compliance assistance effort other enforcement related communication or contact by agency personnel are provided with a means to comment on the enforcement activity conducted by this personnel.

To implement this statutory provision, the Small Business Administration has requested that agencies include the following language on agency publications and notices which are provided to small businesses concerns at the time the enforcement action is undertaken. The language is as follows:

Your Comments Are Important

The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small businesses about federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions of [insert agency name], call [provide telephone number].

HUD intends to work with the Small Business Administration to provide small entities with information on the Fairness Boards and National Ombudsman program, at the time enforcement actions are taken, to ensure that small entities have the full means to comment on the enforcement activity conducted by HUD. HUD intends to include this language in HUD general circulation issuances and publications regarding enforcement actions. HUD welcomes comments on the manner in which it has implemented SBREFA to date, and the additional action intended to be taken as described in this notice.

Dated: May 14, 1998.

Andrew Cuomo,

Secretary.

[FR Doc. 98–13636 Filed 5–20–98; 8:45 am]

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