south of Henderson, a distance of about 13.4 miles. The NCDOT Transportation Improvement Program 1988–1989 includes this project as part of the Strategic Corridor linking Raleigh and Henderson. Improvements to the corridor are considered necessary to increase safety and traffic service.

Alternatives under consideration include: (1) The "no-build", (2) improving existing facilities, and (3) partial relocation.

Solicitation of comments on the proposed action are being sent to appropriate Federal, State and local agencies. A complete public involvement program has been developed for the project to include public meetings and a public hearing to be held in the study area. Information on the time and place of the public hearing will be provided in the local news media. The draft EIS will be available for public and agency review and comment prior to the public hearing. No formal scoping meeting is planned at this time.

To assure that the full range of issues related to this proposed action are addressed and all significant issues identified, comments and suggestions are invited from all interested parties. Comments or questions concerning this proposed action and the EIS should be directed to the FHWA at the address provided above.

(Catalogue of Federal Domestic Assistance Program Number 20.205, Highway Planning and Construction. The regulations implementing Executive Order 12372 regarding inter-governmental consultation on Federal programs and activities apply to this program).

Robert L. Lee,

District Engineer Raleigh, North Carolina.

[FR Doc. 89–19336 Filed 8–16–89; 8:45 am]

BILLING CODE 4910-22-M

Office of Hearings

[Docket 46438]

U.S.-Japan Service Case; Assignment of Proceeding

Served: August 11, 1989.

This proceeding has been assigned to Administrative Law Judge Ronnie A. Yoder. All future pleadings and other communications regarding the proceeding shall be served on him at the Office of Hearings, M-50, Room 9228, Department of Transportation, 400 Seventh Street, SW., Washington, DC 20590. Telephone: (202) 366–2142.

William A. Kane, Jr.,

Chief Administrative Law Judge.

[FR Doc. 89–19272 Filed 8–16–89; 8:45 am]

BILLING CODE 4910-62-M

DEPARTMENT OF THE TREASURY

Public Information Collection Requirements Submitted to the Office of Management and Budget for Review

Date: August 11, 1989.

The Department of the Treasury has made revisions and resubmitted the following public information collection requirement(s) to the Office of Management and Budget (OMB) for review and clearance under the Paperwork Reduction Act of 1980, Public Law 96–511. Copies of the submission(s) may be obtained by calling the Treasury Bureau Clearance Officer listed. Comments regarding this information collection should be addressed to the OMB reviewer listed and to the Treasury Department Clearance Officer, Department of the Treasury, Room 2224, 1500 Pennsylvania Avenue, NW., Washington, DC 20220.

Internal Revenue Service

OMB Number: 1545–0998.
Form Number: 8615.
Type of Review: Resubmission.
Title: Computation of Tax for Children Under Age 14 Who Have Investment Income of More Than $1,000.
Description: Under section 1 (i), children under age 14 who have unearned income may be taxed on part of that income at their parent's tax rate. Form 8615 is used to see if any of the child's unearned income is taxed at the parent's rate and, is so, to figure the child's tax on his or her unearned income and earned income, if any.
Respondents: Individuals or households.
Estimated Number of Respondents: 500,000.
Estimated Burden Hours Per Response/Recordkeeping:

Recordkeeping	13 minutes.
Learning about the law or the form	11 minutes.
Preparing the form	37 minutes.
Copying, assembling, and sending the form to IRS	17 minutes.

Frequency of Response: Annually.
Estimated Total Recordkeeping/Reporting Burden: 655,000 hours.
Clearance Officer: Garrick Shear (202) 535–4297, Internal Revenue Service, Room 5571, 1111 Constitution Avenue, NW., Washington, DC 20224.
OMB Reviewer: Milo Sunderhauf (202) 395–6880, Office of Management and Budget, Room 3001, New Executive Office Building, Washington, DC 20503.

Lois K. Holland,

Departmental Reports Management Officer.

[FR Doc. 89–19342 Filed 8–16–89; 8:45 am]

BILLING CODE 4810-25-M

Public Information Collection Requirements Submitted the Office of Management and Budget for Review

Date: August 11, 1989.

The Department of Treasury has submitted the following public information collection requirement(s) to the Office of Management and Budget (OMB) for review and clearance under the Paperwork Reduction Act of 1980, Public Law 96–511. Copies of the submission(s) may be obtained by calling the Treasury Bureau Clearance Office listed. Comments regarding this information collection should be addressed to the OMB reviewer listed and to the Treasury Department Clearance Officer, Department of the Treasury, Room 2224, 1500 Pennsylvania Avenue, NW., Washington, DC 20220.

Internal Revenue Service

OMB Number: 1545–0236.
Form Number: 11–C.
Type of Review: Revision.
Title: Stamp Tax Registration Return for Wagering.
Description: Form 11–C is used to register persons accepting wagers (Internal Revenue Code section 4412). IRS uses this form to register the respondent, collect the annual stamp tax (Internal Revenue Code section 4412) and to verify that the tax on wagers is reported on Form 730.
Respondents: Individuals or households, Businesses or other for-profit.
Estimated Number of Respondents: 3,500.
Estimated Burden Hours Per Response/Recordkeeping:

Recordkeeping	7 hours, 10 minutes.
Learning about the law or the form	2 hours, 2 minutes.
Preparing the form	4 hours, 5 minutes.

Copying, assembling, and sending the form to IRS	32 minutes.

Frequency of Response: Annually.

Estimated Total Recordkeeping/Reporting Burden: 48,405 hours.

OMB Number: 1545–1007.

Form Number: 8606.

Type of Review: Revision.

Title: Nondeductible IRA Contributions, IRA Basis, and Nontaxable IRA Distributions.

Description: Internal Revenue Code section 408(o) allows taxpayers to elect to make nondeductible contributions to individual retirement plans. This section also requires taxpayers to report to the Service certain information regarding nondeductible contributions.

Respondents: Individuals or households.

Estimated Number of Respondents: 997,748.

Estimated Burden Hours Per Response/Recordkeeping:

Recordkeeping	26 minutes.
Learning about the law or the form	7 minutes.
Preparing the form	22 minutes.
Copying, assembling, and sending the form to IRS	20 minutes.

Frequency of Response: Annually.

Estimated Total Recordkeeping/Reporting Burden: 1,267,140 hours.

Clearance Officer: Garrick Shear (202) 535–4297, Internal Revenue Service, Room 5571, 1111 Constitution Avenue, NW., Washington, DC 20224.

OMB Reviewer: Milo Sunderhauf (202) 395–6880, Office of Management and Budget, Room 3001, New Executive Office Building, Washington, DC 20503.

Lois K. Holland,

Departmental Reports Management Officer.

[FR Doc. 89–19343 Filed 8–16–89; 8:45 am]

BILLING CODE 4810-25-M

Sunshine Act Meetings

Federal Register

Vol. 54, No. 158

Thursday, August 17, 1989

This section of the FEDERAL REGISTER contains notices of meetings published under the "Government in the Sunshine Act" (Pub. L. 94-409) 5 U.S.C. 552b(e)(3).

FEDERAL ELECTION COMMISSION

DATE AND TIME: Tuesday, August 22, 1989, 10:00 a.m.

PLACE: 999 E. Street, NW., Washington, DC

STATUS: This meeting will be closed to the public.

ITEMS TO BE DISCUSSED:

Compliance matters pursuant to 2 U.S.C. 437g.
Audits conducted pursuant to 2 U.S.C. 437g, 438(b), and Title 26, U.S.C.
Matters concerning participation in civil actions or proceedings or arbitration.
Internal personnel rules and procedures or matters affecting a particular employee.

DATE AND TIME: Thursday, August 24, 1989, 10:00 a.m.

PLACE: 999 E. Street, NW., Washington, DC (Ninth Floor).

STATUS: This meeting will be open to the public.

MATTERS TO BE CONSIDERED:

Setting of Dates for Future Meetings.
Correction and Approval of Minutes.
Regulations: 11 CFR parts 4 and 5—Notice of Proposed Rulemaking
FY 1991 Budget Request
Administrative Matters

PERSON TO CONTACT FOR INFORMATION: Mr. Fred Eiland, Information Officer, Telephone: 202-376-3155.

Marjorie W. Emmons,
Secretary of the Commission.

[FR Doc. 89-19452 Filed 8-15-89; 10:58 am]
BILLING CODE 6715-01-M

LEGAL SERVICES CORPORATION

Committee on the Provision for the Delivery of Legal Services Meeting

TIME AND DATE: The meeting will take place on Thursday, August 24, 1989, from 9:00 a.m. until 6:00 p.m. and continue on Friday, August 25, 1989, from 9:00 a.m. until 12:00 p.m., or until all official business has been completed.

PLACE: Washington Marriott Hotel, Dupont Ballroom, 1221 22nd Street NW., Washington, DC 20037.

STATUS OF MEETING: Open. All persons wishing to address the Legal Services Corporation Board of Directors at its public meetings must register with the Secretary of the Corporation, Maureen R. Bozell. Other members of the public may address a meeting of the Board upon invitation of the Chairman of the meeting.

MATTER TO BE CONSIDERED:

1. Approval of Agenda
2. Approval of Minutes June 12-13, 1989
3. Consideration of Competition for Federal Legal Services Grants:
   Discussion Topics to Include:
   —Competition Models Used by Selected Federal Agencies:
   —Requirements for a Solicitation for a Legal Services Grant;
   —Issues Presented at the June 12-13, 1989, Meeting in Schaumburg, IL: and
   —Presentation by Douglas J. Besharov, of the American Enterprise Institute.
4. Public comment.

CONTACT PERSON FOR MORE INFORMATION: Maureen R. Bozell, Executive Office, (202) 863-1839.

Date issued: August 15, 1989.

Maureen R. Bozell,
Corporation Secretary.

[FR Doc. 89-19531 Filed 8-15-89; 3:36 pm]
BILLING CODE 7050-01-M

federal register

Thursday
August 17, 1989

Part II

Environmental Protection Agency

40 CFR Part 60

Standards of Performance for New Stationary Sources; Fluid Catalytic Cracking Unit Regenerators; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-3104-8]

RIN 2060-AA36

Standards of Performance for New Stationary Sources; Fluid Catalytic Cracking Unit Regenerators

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: Standards of performance to limit sulfur oxide (SO_x) emissions from new, modified, and reconstructed fluid catalytic cracking unit (FCCU) regenerators were proposed in the **Federal Register** on January 17, 1984 (49 FR 2058). Revisions to the proposed standards were proposed in the **Federal Register** on November 8, 1985 (50 FR 46464). This action promulgates these standards of performance for FCCU regenerators. These standards implement section 111 of the Clean Air Act and are based on the Administrator's determination that emissions from petroleum refineries cause, or contribute significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare. The intended effect of these standards is to require all new, modified, and reconstructed FCCU regenerators to achieve emission levels that reflect the best demonstrated system of continuous emission reduction considering costs, non-air quality health, and environmental and energy impacts. The standards define an FCCU to include fluidized bed treatment processes requiring the continuous regeneration of catalyst or contact materials by burning off coke and other deposits. New, modified, and reconstructed process units fitting this definition would be required to achieve the FCCU carbon monoxide (CO), particulate, and opacity standards in 40 CFR part 60, subpart J, as well as the SO_x standards promulgated today.

DATES: This regulation is effective August 17, 1989.

These standards of performance become effective upon publication but apply to affected facilities for which construction, modification, or reconstruction commenced after January 17, 1984. Any FCCU that was constructed, modified, or reconstructed on or before January 17, 1984 to use a contact material for removing impurities from feedstock (rather than a catalyst for cracking feedstock) is not retroactively subject to the FCCU standards for particulate, opacity, and CO emissions.

Under section 307(b)(1) of the Clean Air Act, judicial review of the actions taken by this notice is available only by the filing of a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit within 60 days of today's publication of this rule. Under section 307(b)(2) of the Clean Air Act, the requirements that are the subject of today's notice may not be challenged later in civil or criminal proceedings brought by EPA to enforce these requirements.

The incorporation by reference of certain publications in these standards is approved by the Director of the Office of the **Federal Register** as of August 17, 1989.

ADDRESSES: *Background Information Document.* The background information document (BID) for the promulgated standards may be obtained from the U.S. EPA Library (MD-35), Research Triangle Park, North Carolina 27711, telephone number (919) 541-2777. Please refer to "Sulfur Oxides Emissions from Fluid Catalytic Cracking Unit Regenerators—Background Information for Promulgated Standards of Performance" (EPA-450/3-82-013b). The BID contains (1) a summary of all the public comments made on the proposed standards and the Administrator's responses to the comments, (2) a summary of the changes made to the standards since proposal, and (3) the final Environmental Impact Statement, which summarizes the impacts of the standards.

Docket. A docket, number A-79-09, containing information considered by EPA in the development of the promulgated standards, is available for public inspection between 8:30 a.m. and 3:30 p.m., Monday through Friday, at EPA's Air Docket (LE-131), Room M-1500, 1st Floor, Waterside Mall, 401 M Street, SW., Washington, DC 20460. A reasonable fee may be charged for copying.

FOR FURTHER INFORMATION CONTACT: For further information and official interpretations of applicability, compliance requirements, and reporting aspects of the promulgated standard, contact the appropriate Regional, State, or local office contact as listed in 40 CFR 60.4. For further information on the background of the regulatory decisions in the promulgated standard, contact Ms. Gail Lacy, Standards Development Branch, Emission Standards Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5261. For further information on the technical aspects of the promulgated standards, contact Mr. Dave Markwordt, Chemicals and Petroleum Branch, Emission Standards Division (MD-13), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-0837. For further information on the testing and monitoring requirements of the promulgated standards, contact Mr. Terry Harrison, Emission Measurement Branch, Technical Support Division (MD-14), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5233.

SUPPLEMENTARY INFORMATION:

I. The Standards

Standards of performance for new sources established under section 111 of the Clean Air Act reflect:

> * * * application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emission reduction, any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated [section 111(a)(1)].

For convenience, this will be referred to as "best demonstrated technology" or "BDT."

As prescribed by section 111, promulgation of these standards was preceded by the Administrator's determination (40 CFR 60.16, 38 FR 15380 dated June 11, 1973) that petroleum refineries contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

The promulgated standards limit SO_x emissions from new, modified, and reconstructed affected facilities. For the purpose of these standards, the affected facility is identified as the FCCU regenerator (or regenerators where an FCCU has multiple regenerators) and air blower. The definition of FCCU in the standards includes units that can process residual feedstocks. These units are commonly referred to as heavy oil cracking (HOC) units and include reduced crude conversion (RCC) units. The definition also includes other process units such as asphalt residual treatment (ART) units that are similar to an FCCU in equipment configuration, operation, and emissions. An ART unit circulates and regenerates a contact material for removing feedstock impurities, including sulfur. Such units constructed, modified, or reconstructed after January 17, 1984, are subject to these standards and to the FCCU standards in 40 CFR part 60 subpart J for particulate matter, CO, and visible emissions.

A refiner can choose from several alternatives to achieve the standards. Each of these alternatives is discussed below.

The standard for FCCU's with add-on controls is applicable if a refiner chooses to use an add-on control device, such as a scrubber. This standard requires that sulfur dioxide (SO_2) emissions from the FCCU regenerator must be reduced by at least 90 percent, or that the SO_2 emissions to the atmosphere must be no greater than 50 parts per million by volume (vppm) whichever is less stringent. The standard for FCCU's with add-on controls now requires determination of compliance on a daily basis, rather than using excess emissions to identify the need for a compliance test. Use of continuous SO_2 monitors, located at the control device inlet and outlet, is required to determine on a continual basis the compliance status of the facility. Only a continuous monitor at the outlet of the control device is required if the owner or operator seeks to comply specifically with only the 50 vppm standard. Because SO_2 monitors are now used for compliance determinations, they are subject to 40 CFR part 60 appendix F, "Quality Assurance Procedures, Procedure 1—Quality Assurance Requirements for Gas Continuous Emission Monitoring Systems Used for Compliance Determinations." The compliance averaging time has changed since proposal from 3 hours to a rolling 7-day average. Minimum data requirements have now been incorporated. The minimum data requirements require 22 valid days of data out of every 30 successive, rolling calendar days. A valid day of data consists of a minimum of 18 valid hours of data, where a valid hour of data consists of at least 2 valid data points. If the continuous emission monitoring system (CEMS) does not collect enough data to meet the minimum data requirement, then other means, such as manual test Methods 6B or 8, or another CEMS must be used to obtain sufficient data to meet the minimum data requirements.

The standard for FCCU's without add-on controls requires that a refiner limit SO_x emissions to the atmosphere from an FCCU to a level less than or equal to 9.8 kilograms (kg)/1,000 kg coke burn-off without the use of an add-on control device. Examples of SO_x control techniques that could be used to achieve this standard include SO_x reduction catalysts and feed hydrotreating. Like the standard for FCCU's with add-on controls, the standard for FCCU's without add-on controls now requires daily compliance determinations. Compliance with the standard is determined by manual stack sampling using EPA Reference Method 1 for sample and velocity traverses, Method 2 calculation procedures for velocity and volumetric flowrate, Method 3 for gas analysis, and Method 8 for determining the SO_x content of the stack gases. The compliance averaging time has also changed since proposal from 3 hours to 7 days, so that daily compliance determinations are made on the basis of a 7-day rolling average. One 3-hour Method 8 test is required each day. Alternative methods may be approved on a case-by-case basis if sufficient data are obtained to show that the data can be used for making compliance determinations on a daily basis.

The feed sulfur cutoff states that FCCU's processing feedstocks with sulfur contents less than or equal to 0.30 percent by weight, averaged over a rolling 7-day period, are exempt from both the standard for FCCU's with add-on controls and the standard for FCCU's without add-on controls. Refiners can use low sulfur feedstocks or hydrotreating to meet this limit. Compliance with the feed sulfur cutoff is determined by sampling the fresh feedstock to the FCCU and determining its sulfur content using American Society for Testing and Materials (ASTM) analytical test methods ASTM D129–64 (Reapproved 1978), ASTM D1552–83, ASTM D2622–87, or ASTM D1266–87. The results are reported as a 7-day rolling average. This represents a change since proposal, when results were reported as a 7-day calendar average. One sample is required per 8-hour period.

Each 7-day period during which the owner or operator does not meet the applicable standards is a violation of that standard. For example, if an owner or operator seeks to comply with the feed sulfur cutoff, each 7-day period for which the average feed sulfur level exceeds 0.30 weight percent is a violation of the standard. Failure to meet the minimum data requirements (that is, 22 valid days of data out of 30 days) during any rolling 30-day period of successive calendar days for the standards for FCCU's with add-on controls is also considered a violation of the standards.

Quarterly reporting is required for all periods in which a violation occurs. These reports include information on any 7-day period during which a violation of the standard has occurred and any 30-day period during which the minimum data requirements have not been met. This information includes the date the violation occurred; an explanation for the violation; whether the violation was concurrent with startup, shutdown, or malfunction of the FCCU or control system; and a description of the corrective action taken, if any. If no violations occur during a quarter, then a semiannual report may be submitted. However, if an owner or operator elects to comply with an alternative standard, a quarterly report must be submitted to the Administrator in the quarter following such a change even if no violations of a standard have occurred. Whether or not a violation has occurred, for any single calendar day in which 18 valid hours of CEMS data, a Method 8 test result, or 3 test results for feed sulfur content were not obtained as required by these standards, the dates for and brief explanations as to why such data were not obtained shall still be included in the quarterly (or semiannual) report. Records of continuous monitoring data and calibrations, supplemental sampling test results, Method 8 test results, feed sulfur test results, and each 7-day average compliance determination must be maintained by the owner or operator of the affected facility and be available for inspection by EPA for 2 years. In addition, the standards require refiners to submit notification and compliance reports in accordance with the General Provisions (40 CFR part 60, subpart A).

The promulgated standards would also amend the standards in Subpart J for fuel gas combustion devices by deleting an incorrect duplication of the definition of excess emissions of SO_2, i.e., deleting 40 CFR 60.105(e)(4).

II. Environmental Impacts

The promulgated standards are based on the application of BDT to control FCCU SO_x emissions. The EPA determined, considering costs, environmental, energy, and non-air quality health impacts that scrubbers effectively control FCCU SO_x emissions and are BDT. However, refiners may also use SO_x reduction catalysts, naturally occurring low sulfur FCCU feedstocks, or hydrotreated FCCU feedstocks to meet these standards.

To estimate the impacts of the promulgated standards, EPA projected that 17 newly constructed, modified, and reconstructed FCCU regenerators would be affected by the standards during the first 5 years after the effective date of the standards. Assuming that scrubbing systems are used at all affected facilities processing feedstocks containing greater than 0.30 weight percent sulfur, EPA estimates that the promulgated standards would reduce fifth year nationwide SO_x emissions by about 69,000 megagrams per year (Mg/yr). If, instead, these same facilities processing feeds greater than 0.30 weight percent sulfur elected to comply with the standard for FCCU's without add-on controls, fifth year nationwide SO_x emissions would be reduced by about 63,000 Mg/yr.

Application of sodium-based scrubbers to control SO_x emissions from the affected facilities would increase fifth year nationwide wastewater discharges by about 2.2×10^6 cubic meters per year (m^3/yr). Wastewater from sodium-based scrubbers designed to control both particulates and SO_x emissions from FCCU's is treated to reduce collected particulates and chemical oxygen demand. The treated discharge from these scrubbers would contain about 90 Mg/yr of suspended solids and chemical oxygen demand, and about 110 gigagrams per year (Gg/yr) of total dissolved solids in the fifth year of the standards. The discharge from sodium-based scrubbers designed to control only SO_x would not produce significant quantities of solid wastes.

The sodium scrubbers that are currently applied to FCCU's control both particulate emissions as well as SO_x emissions. With this type of scrubber, an additional particulate control device would not be required to achieve the current FCCU particulate standard. Control of FCCU particulate emissions (primarily catalyst fines) by a sodium scrubber does not incrementally increase the dry weight of solid wastes over control by a dry particulate control device, such as an electrostatic precipitator (ESP). Therefore, the amount of particulates collected by the sodium scrubbers are not "chargeable" to the SO_x standards. However, particulates collected in a scrubber would be wet, and thus, weigh more and encompass a larger volume. The increase due to the amount of water added to the solids is "chargeable" to the SO_x standards. The fifth year nationwide incremental increase in solid wastes produced by application of sodium scrubbers is estimated to be about 14 Gg/yr.

At refinery locations where the disposal of a treated wastestream from a sodium scrubber is not permitted, a refiner would need to use other SO_x control techniques with minimal wastewater impacts. Alternative scrubbing systems include dual alkali or spray drying scrubbing systems, which produce no significant liquid wastes but instead produce solid wastes. Other alternatives are Wellman-Lord or citrate scrubbing systems, which produce no significant liquid wastes but instead produce a salable sulfur product. If dual alkali scrubbers are used to control SO_x emissions from all affected facilities with feed sulfur levels above 0.30 percent, solid wastes would increase over baseline by 325 Gg/yr in the fifth year.

The use of SO_x reduction catalysts may increase FCCU particulate emissions, and hence, increase solid wastes collected by the particulate control device. It is difficult to approximate this increase, however, because the catalyst technology is still in the developmental stages. It is unlikely that the use of SO_x reduction catalysts would significantly increase FCCU solid waste impacts over current levels. Wastewater discharges would not increase with the use of SO_x reduction catalysts.

III. Energy Impacts

The promulgated standards would have a small impact on nationwide energy consumption. Sodium scrubbers would increase FCCU energy consumption for new, modified, and reconstructed FCCU's by about 0.2 to 2.0 percent, depending on the regeneration mode of the FCCU and type of venturi scrubber used. Other scrubbing systems, particularly regenerable systems such as Wellman-Lord and citrate scrubbers, would have a greater energy impact. However, EPA expects few refiners to use regenerable scrubbing systems. No energy increase is expected from use of SO_x reduction catalysts.

IV. Cost Impacts

The costs for these standards have changed somewhat since proposal. Costs were revised to account for inflation and to better reflect the cost of retrofitting scrubbers at existing refineries. The EPA estimates that if sodium-based scrubbers are used at all affected facilities with feed sulfur levels above 0.30 percent by weight, the promulgated standards would result in a 5-year total nationwide capital cost of $117 million and an annual cost of $45 million (reported in fourth quarter 1984 dollars) in the fifth year after the effective date of the standards. Units processing feeds with sulfur contents of 0.30 percent by weight would be below the feed sulfur cutoff and, therefore, not need to install a scrubber. Where sodium scrubbers are not applicable, dual alkali scrubbers could be used at a similar cost to sodium scrubbers. If all affected facilities used SO_x reduction catalysts, SO_x emissions control would cost about $20 million to $50 million in the fifth year of the standards. SO_x reduction catalyst costs are presented as a range because the technology is under development. The upper end of the range represents a catalyst formulation that is the earlier stages of development; the developer of this catalyst expects the cost to decrease as the catalyst formulation is produced in greater quantities.

The cost of SO_x control, if all affected facilities with feed sulfur levels greater than 0.30 weight percent used scrubbers, would be approximately $660/Mg of SO_x removed. Based on catalyst developer claims of SO_x reduction catalyst performance and cost, SO_x reduction catalysts, when used at those affected facilities with feed sulfur levels greater than 0.30 weight percent but less than or equal to 1.5 weight percent, are estimated to cost from $320 to $850/Mg of SO_x removed. Affected facilities processing feeds containing greater than 1.5 weight percent sulfur would likely use scrubbers. These affected facilities would incur a cost of less than $660/Mg of SO_x removed.

The cost of scrubbing for FCCU's processing feeds containing slightly greater than 0.30 weight percent sulfur would be approximately $1,900/Mg of SO_x removed. However, EPA does not expect refiners processing feeds with sulfur contents slightly greater than 0.30 weight percent actually to incur a cost of $1,900 to remove each megagram of SO_x emissions. This is because these refiners are the ones most likely to use SO_x reduction catalysts rather than install a scrubber.

V. Economic Impact

The economic impact of the standards will be small even if all affected facilities use flue gas scrubbers. The price increases presented in the proposal BID were all less than 0.4 percent. Using the revised control costs and second quarter 1984 product prices, that figure increases to approximately 0.8 percent in the worst case. Even without passing through price increases, the standards are not expected to reduce the profitability of FCCU operations to the point where planned investments would be postponed. The EPA does not consider these percentages sufficiently high to deter a decision to install an FCCU that is otherwise economically justified.

The environmental, energy, and economic impacts are discussed in greater detail in the BID for the proposed standards, "Sulfur Oxides Emissions from Fluid Catalytic Cracking Unit Regenerators—Background

Information for Proposed Standards," EPA-450/3-82-013a.

VI. Public Participation

Prior to proposal of the standards, interested parties were advised by public notice in the Federal Register (46 FR 55000, November 5, 1981) of a meeting of the National Air Pollution Control Techniques Advisory Committee to discuss the standards for FCCU regenerators recommended for proposal. This meeting was held on December 1, 1981. The meeting was open to the public and each attendee was given an opportunity to comment on the standards recommended for proposal.

The proposed standards were published in the Federal Register on January 17, 1984 (49 FR 2058). The preamble to the proposed standards described the availability of the BID, "Sulfur Oxides Emissions from Fluid Catalytic Cracking Unit Regenerators—Background Information for Proposed Standards," EPA-450/3-82-013a, which described in detail the regulatory alternatives considered and the impacts of those alternatives. Public comments were solicited at the time of proposal and copies of the proposal BID were distributed to interested parties. The Agency published a revised proposal in the Federal Register on November 8, 1985 (50 FR 46464). Public comments on the revised proposal were solicited at the time of their proposal and copies of the revised proposal were distributed to interested parties.

The public was also given the opportunity for oral presentation of data, views, or arguments concerning the proposed standards in accordance with section 307(d)(5) of the Clean Air Act. No one requested a public hearing, so a public hearing was not held.

The original public comment period was from January 17 to April 3, 1984. This comment period was reopened on November 8, 1985, and extended through December 9, 1985, in order to allow interested parties to comment specifically on the proposed revisions. A total of 30 comment letters were received. The comments have been carefully considered and, where determined to be appropriate by the Administrator, changes have been made in the proposed standards.

VII. Significant Comments and Changes to the Proposed Standards

Comments on the proposed standards were received from industry, State and local air pollution control agencies, trade associations, a private individual, and the Office of Management and Budget (OMB). A detailed discussion of these comments and responses can be found in the promulgation BID, which is referred to in the **ADDRESSES** section of this preamble. The summary of comments and responses in the BID serve as the basis for the revisions that have been made to the standards between proposal and promulgation. The major comments and responses are summarized in this preamble. Most of the comment letters contained multiple comments. The comments have been divided into the following areas: The Standards, Control Technologies and Economic Impacts, Compliance Testing and Monitoring, Compliance, and Modification/ Reconstruction.

The Standards

Applicability

Comment (Regulated Pollutant): In the revised proposed standards (50 FR 46464), the Agency proposed to change the regulated pollutant from SO_x to SO_2 for the standard with add-on controls, but keep SO_x as the regulated pollutant for the standard without add-on controls. Comments were received only on SO_x as the regulated pollutant for the standard without add-on controls.

Several commenters suggested that EPA use SO_2 rather than SO_x as the regulated pollutant for the standard for SO_x reduction catalysts. Among the arguments presented by the commenters were that: (1) Emerging SO_x reduction catalyst data indicate that sulfur trioxide (SO_3) is unaffected by the catalysts; (2) preliminary data previously submitted to EPA from several SO_x reduction catalyst trials at one of their refineries generally indicate only an insignificant amount of SO_3 in the SO_x emissions; (3) using SO_2 as the regulated pollutant enables the same monitoring technique (proven SO_2 monitors) to be used as for add-on scrubber technology, resulting in cost savings and sample consistency and reliability; and (4) other refinery sources are only regulated for SO_2 and EPA usually regulates only SO_2.

Response: The Agency has considered the arguments presented by the commenters and reviewed the data available on the composition of SO_x when using SO_x reduction catalysts. After this review, the Agency still believes that the most appropriate regulated pollutant for SO_x reduction catalysts is SO_x, not SO_2.

The Agency recontacted SO_x reduction catalyst vendors to review the mechanism by which SO_x reduction catalysts reduce total SO_x emissions. The SO_x reduction catalyst vendors indicate that SO_x reduction catalysts preferentially remove SO_3, forming a metal sulfate compound that is much more stable than the metal sulfite compound formed when the SO_2 reacts with the catalyst. As the SO_x reduction catalyst picks up more and more SO_3, the equilibrium balance is disturbed. To regain equilibrium, more SO_2 becomes SO_3. If the rate of SO_2 to SO_3 is less than the rate of metal sulfate formation (SO_3 plus metal oxide), then the SO_3 percentage in the FCCU emissions will decrease. If the SO_2 to SO_3 rate is faster than the metal sulfate formation rate, then the ratio of SO_2 to SO_3 will remain the same. In order for the percentage of SO_3 to increase, other operating parameters of the regenerator would have to change in order to change the thermodynamic equilibrium. To ensure maximum SO_x removal efficiency, the owner or operator would likely operate a regenerator, to the extent possible, in such a manner that the SO_2 to SO_3 rate is not limiting; that is, create conditions within the regenerator that increase the SO_3 percentage.

The Agency again reviewed the data on the SO_2/SO_3 ratio in regenerator emissions, including that most recently submitted by several commenters. The Agency requested in the revised proposal that any data that were available on this be submitted. Very little data were submitted. The data base, therefore, remains very limited and inconclusive. The more recent data generally tend to have a lower percentage of SO_3 than the earlier data. Some of the recent data still suggest, however, that there is a potential for large amounts of SO_3 to be emitted, which would be undetected by a standard using SO_2 as the regulated pollutant. Thus, regulating SO_2 only will not necessarily reflect the potential control of SO_x that can be obtained by SO_x reduction catalysts.

The Agency requested, but did not receive, data on the possibility that the plume opacity standard for FCCU's may help limit the emissions of SO_3. Plume opacity is affected by the condensation of SO_3 and, to the extent this condensation affects the ability of a source to comply with the opacity standard, it may also help limit the emissions of SO_3. If sufficient data had been presented, the Agency would have considered changing the regulated pollutant for FCCU's without add-on controls from SO_x to SO_2 so that SO_2 CEMS's could be used for compliance determinations.

The arguments relating to the advantages of SO_2 monitoring are outweighed by the need for an SO_x standard for the reasons described above. The fact that other refinery sources are only regulated for SO_2 sheds no light on whether an SO_x standard is appropriate for this source.

Comment (Affected Facility): Several commenters stated that the designation of the affected facility should be broadened to include the entire FCCU, and that the definition of "fresh feed" should be clarified.

Response: At proposal, the affected facility was designated as each individual FCCU regenerator and air blower. The rationale for this selection of the affected facility was presented in the preamble to the proposed standards (49 FR 2060). As stated in the preamble, SO_x are generated in and emitted from the FCCU regenerator. The designation of the regenerator of each FCCU as the affected facility, rather than the entire FCCU, would lead to bringing replacement equipment under these standards sooner and thus, would adhere to the purpose of section 111 of the Clean Air Act.

The EPA anticipates that few, if any, FCCU's utilizing multiple regenerators will become subject to these standards over the next 5 years. However, identifying each FCCU regenerator as the affected facility for multiple regenerator configurations is unreasonable. If only one regenerator in a multiple regenerator configuration were to become subject to the standards, it would be impossible in some multiple regenerator ducting arrangements to isolate and measure the SO_x content of the exhaust gases from the affected regenerator. Furthermore, because the refiner would want to minimize the cost and downtime for revamping work on the unit, it is unlikely that only one regenerator in a multiple regenerator configuration would be modified or reconstructed without the others. Therefore, the affected facility is now defined to include all regenerators serving an FCCU reactor.

The proposed definition of "fresh feed" specifically excluded those petroleum derivatives recycled within the FCCU. To ensure that a refiner would not circumvent the feed sulfur cutoff by adding low-sulfur content recycle from the fractionator and gas recovery unit, EPA has revised the definition of "fresh feed" in the regulation. The revised definition specifically identifies petroleum derivatives from the FCCU, fractionator, and gas recovery unit as recycle, and thus excludes them from the definition of "fresh feed."

Comment (RCC/ART Units): One commenter stated that the proposed standards should not apply to RCC process or ART units, because the RCC unit is designed to process residual feedstocks, and the ART unit is a feedstock upgrading unit, and, therefore, these units are not FCCU's.

Response: To upgrade residual feedstocks and to increase gasoline and middle distillate product yields, new processes termed HOC, which includes RCC, and ART are being installed at refineries. The HOC units are FCCU's that process residual and other heavy oil feedstocks. As in a conventional FCCU, emissions occur as a result of catalyst regeneration. Sulfur oxide emissions may, in fact, be greater from HOC units than from other FCCU's because HOC feedstocks have a higher coke make rate than gas oil feeds and a greater portion of the sulfur in HOC feedstocks forms coke than that in gas oil feeds. The EPA's analysis of SO_x emissions, control costs, and cost effectiveness for HOC units showed that the proposed standards for FCCU's are achievable and affordable for HOC units. The results of this analysis were presented in Appendix F of the proposal BID.

Emissions, emission control, and control costs for the ART process were further evaluated by EPA. The differences stated by the commenter between an ART unit and an FCCU do exist: The ART process does not employ a catalyst, but rather uses an inert microspheric contact material that collects contaminants; the objective of the ART process is feedstock upgrading, not processing; and some of the operating conditions may vary significantly.

Nevertheless, important similarities in regenerator configuration, operation, and emissions exist that warrant the regulation of an ART unit under the FCCU new source performance standards (NSPS). For both an ART unit and a conventional FCCU, regeneration is performed to burn off coke from the catalyst or contact material, thereby restoring it for reuse in the unit. Opacity and emissions of CO, SO_x, and particulate from an ART unit regenerator during normal operation are expected to be within the range of emissions from all types of FCCU regenerators, including those from HOC units. The EPA evaluated control feasibility and cost for an ART unit based on reported emissions and determined that control of an ART unit by a scrubber was applicable and had a reasonable cost. Based on a scrubber SO_x efficiency of 90 percent, the scrubber cost effectiveness calculated for the ART unit is below the range of cost effectiveness expected for FCCU's. In addition, costs to control CO emissions, if necessary, and particulate emissions are estimated to be reasonable.

The similarity in emissions from the regenerator and the availability of control equipment at a reasonable cost indicate that the ART unit regenerator can meet the FCCU standards. The facts that the objective of the ART process is different than that of the FCCU and that the material being regenerated is not a catalyst are not significant reasons to support the contention that an ART unit should not be subject to the FCCU NSPS. Therefore, the final standards require, as proposed, that an ART unit, HOC unit, or any other similar type of fluidized bed treatment unit regenerator achieve the FCCU particulate, opacity, CO, and SO_x standards.

Format of the Standards

Comment: Several commenters stated that EPA should establish a single SO_x standard for FCCU's because it would allow refiners the options and flexibility of determining the most cost-effective method of meeting that limit and it would comply with Section 111(h) of the Clean Air Act, which implies that the Administrator should prescribe a performance standard rather than a work practice or equipment standard, where feasible to do so.

Response: To develop SO_x emission standards for FCCU's, EPA evaluated all available techniques for controlling FCCU SO_x emissions. Upon thorough consideration of the availability, SO_x emission reduction capability, and impacts associated with each of these techniques, EPA determined that scrubbing systems effectively control SO_x emissions from all types of FCCU applications, and represent BDT for FCCU SO_x and SO_2 emissions.

The percent reduction format was selected because it best reflects the performance of add-on controls for all expected feed sulfur levels. This is consistent with section 111(a)(1), which requires that the standard reflect application of BDT.

However, for many FCCU applications, SO_x emissions can be reduced effectively and continuously without the use of add-on controls. This can be achieved by using SO_x reduction catalysts or low sulfur FCCU feedstocks obtained by either hydrotreating high sulfur feedstocks or processing naturally occurring low sulfur crude oils. Although these techniques may be less effective at reducing SO_x emissions than scrubbers for some FCCU applications, they have lower costs and smaller non-air environmental impacts than scrubbers. The EPA judged that it is reasonable to give up some emission reduction by establishing a standard without add-on controls in return for the other benefits afforded by using SO_x reduction catalysts, hydrotreating, or low sulfur feedstocks instead of scrubbers. Therefore, EPA has established alternative standards for the sources that can effectively and continuously reduce SO_x emissions without the use of add-on controls. If a refiner believes that using SO_x reduction catalysts, hydrotreating, or low sulfur feedstocks for his particular FCCU application will not achieve the standard without add-on controls, then the refiner can still install and operate an add-on control device that achieves 90 percent reduction of SO_2 emissions.

The standards are performance standards and are consistent with section 111 of the Clean Air Act. Neither the add-on control standard nor the standard for FCCU's without add-on controls specifies the type of controls that must be used or exactly how the controls are to be operated to achieve the standard.

One commenter noted that by partial scrubbing of the FCCU regenerator exhaust gases, the emission level represented by the standard for FCCU's without add-on controls could be achieved for some FCCU applications. However, the 90 percent standard is intended to reflect the capability of scrubbers, which can achieve 90 percent control of the entire exhaust stream. A relaxation of the standard to 9.8 kg SO_x/1,000 kg coke burn-off would cause it to no longer reflect the capability of scrubbers.

Comment: Commenters questioned the coke burn-off format proposed by EPA for the standard for FCCU's without add-on controls. They noted that the coke burn-off format does not allow for variation in coke sulfur content and will discourage process improvements. They stated that EPA should consider a percent reduction format and a format in kilograms of SO_x per thousand barrels of feed.

Response: Based on a sensitivity analysis presented in Appendix F of the proposal BID, EPA concluded that the coke burn-off format relates well to normal fluctuations in SO_x emissions from FCCU's processing a variety of feeds. This is because SO_x emissions are related directly to the coke sulfur content. Normally, FCCU's are operated to limit the amount of coke that can be burned off in the regenerator. Process improvements that reduce the coke make rate are made to allow the refiner to process more feed through the unit until the unit is again limited in the amount of coke it can burn off. An example of a process improvement that results in reduced coke make is high temperature regeneration (HTR). The initial result of HTR would be reduced SO_x emissions from FCCU's on a mass basis. However, SO_x emissions in terms of coke burn-off would remain the same because SO_x emissions are related to the sulfur on coke. Thus, the refiner could increase throughput until the unit is again coke burn-off limited and still be within the standard even though emissions would increase. This format offers greater refining flexibility than a mass of SO_x per unit of feed basis. The commenters provided no new information to refute this conclusion.

A sliding scale format that allows for variation in coke sulfur content would be difficult to enforce because the sulfur content of the coke on catalyst is not readily obtainable. For this reason, EPA considers a sliding scale format unreasonable.

The EPA considered a percent reduction format for the standard for FCCU's without add-on controls, but rejected it because of compliance considerations. With SO_x reduction catalysts, there is no uncontrolled or inlet SO_x concentration to measure. Thus, it would be impossible to determine through stack testing the percent reduction being achieved by the catalysts. An alternative method would be to estimate the percent reduction achieved by SO_x reduction catalysts using EPA's correlation of feed sulfur with SO_x emissions. However, EPA's correlation represents an average for all FCCU's and feedstocks. While the correlation is useful for analyzing the overall impact of the standards, inlet SO_x concentrations may be lower or higher than the level predicted by the correlation for a specific FCCU and feedstock. Thus, the correlation cannot be used on a case-by-case basis. The cost to develop a separate correlation for each feedstock and FCCU affected by the standards is unreasonable. Because there is not a practical method for determining the SO_x inlet concentration when using SO_x reduction catalysts, EPA did not select a percent reduction format.

The EPA considers the coke burn-off format reasonable because of its direct relationship to the sulfur-on-coke relationship. The coke burn-off format is identical to the format selected for the NSPS particulate standard; the coke burn-off rate can be recorded reasonably and would be readily available.

Level of Standards

Comment (Without Add-On Controls): Many commenters stated that the standard for FCCU's without add-on controls should be set at 13 kg SO_x/1,000 kg coke burn-off because 80 percent reductions by SO_x reduction catalysts are not supported by the limited commercial tests cited by EPA. Also, a 13 kg SO_x/1,000 kg coke burn-off emission limit would allow more refiners to use the catalysts rather than add-on controls. The commenters believe that SO_x reduction catalysts are the only cost-effective and environmentally acceptable control alternative. One commenter stated that the emission reduction required by the standard for FCCU's without add-on controls is essentially equivalent to the level of control required by the Texas Air Control Board (TACB) to control FCCU SO_x emissions.

Response: The EPA disagrees with the comment that SO_x reduction catalysts are the only cost-effective and environmentally acceptable control alternative. The EPA determined, considering costs, environmental, energy, and non-air quality health impacts, that scrubbers effectively control FCCU SO_x emissions and are BDT. Furthermore, as an alternative to using SO_x reduction catalysts, refiners may use hydrotreating or low sulfur feedstocks to achieve compliance with the 9.8 kg SO_x/1,000 kg coke burn-off level.

The level of the standard (9.8 kg SO_x/1,000 kg coke burn-off) was selected to allow refiners flexibility to use SO_x reduction catalysts with best currently available performance, and to encourage the further development of the catalyst technology. For many feedstocks, especially those with lower sulfur content, the emission reduction needed to achieve the level of the standard is less than 80 percent. For example, a feedstock with 0.5 weight percent sulfur would need approximately 50 percent reduction in SO_x emissions to achieve the level of the standard. In response to the comments, EPA contacted a number of companies known to be developing SO_x reduction catalysts to request updated information on the performance and availability of developmental SO_x reduction catalysts. Based on a survey of SO_x reduction catalyst developers, current commercial SO_x reduction catalyst test data have been reported by the developers to reduce FCCU SO_x emissions by 65 to 75 percent. The test data reported by the developers span a wide range of catalyst performance; some data points show catalyst performance as high as 90 percent. As the technology continues to develop, refiners will be able to use the catalyst technology to achieve the standard for a greater range of feedstocks.

Based on the results of SO_X reduction catalyst tests, EPA believes the level of the standard for FCCU's without add-on controls is reasonable. The determination of the level of this standard included consideration of the benefits of SO_X reduction catalysts and the increase in SO_X emissions compared to the BDT of scrubbing. Because the primary purpose of the standards is to reduce future FCCU SO_X emissions, and scrubbers can achieve cost-effective emission reductions, EPA concluded that it is not reasonable to further increase allowable emissions by raising the level of the standard. Should a refiner find that SO_X reduction catalysts will not reduce emissions sufficiently to achieve the 9.8 kg SO_X/1,000 kg coke burn-off level, the refiner still has the flexibility to use hydrotreating alone or in combination with SO_X reduction catalysts, to choose a lower sulfur content feedstock, or to install a scrubber.

Comment (Feed Sulfur Cutoff): Two commenters stated that an arbitrary feed sulfur cutoff of 0.30 weight percent sulfur is too restrictive, suggesting that a feed sulfur cutoff equivalent to 9.8 kg SO_X/1,000 kg coke burn-off be established by developing a correlation between feed sulfur content and SO_X production based on test data.

Response: The selection of the feed sulfur cutoff level of 0.30 weight percent was not arbitrary. As was discussed in the preamble to the proposed standards, the feed sulfur cutoff level was selected based on consideration of the costs for application of scrubbers to control SO_X emissions from FCCU's processing low sulfur feedstocks, and the feedstock sulfur levels refiners are expected to be processing if they elect to use naturally occurring low sulfur feed or to hydrotreat high sulfur feeds.

A correlation between FCCU feed sulfur content and SO_X emissions is presented on p. 3–18 of the proposal BID. The correlation is based on test data for a large number of FCCU's and feedstock types. Based on this correlation, an FCCU SO_X emission level of 9.8 kg SO_X/1,000 kg coke burn-off corresponds to a feed sulfur level of approximately 0.3 weight percent. Thus, the feed sulfur cutoff level established by EPA is approximately equivalent to the standard for FCCU's without add-on controls.

Averaging Times

Comment: Commenters stated that the averaging time for the standards should be increased. Several commenters suggested a 7-day averaging period for compliance because it would be consistent with the averaging time for the feed sulfur cutoff; no process variables could be adjusted in a 3-hour period to regulate SO_2 emissions when using SO_X reduction catalysts; and 7 days would account for variation in SO_2 inlet concentrations to the control device whereas 3 hours would not.

Response: After assessing the long-term variability by statistically analyzing in a times series analysis of the continuous SO_2 monitoring data from an EPA study of a sodium scrubber applied to an FCCU, the EPA agrees that the averaging time for compliance with the standards for FCCU's with and without add-on controls should be lengthened. The revised proposed standards included a revision of the compliance averaging time from 3 hours to 7 days. Six commenters agreed with EPA's revision. No commenters disagreed.

Comment: Two commenters stated that the averaging period for the feed sulfur cutoff should be a 30-day rolling average period. The use of the 30-day period would be appropriate because a 30-day rolling average period is used for the fossil fuel-fired steam generator NSPS.

Response: Whenever practical, EPA determines NSPS regulatory requirements on an individual source category basis. It is not appropriate to use a 30-day rolling average period for the FCCU feed sulfur cutoff standard simply to copy the fossil fuel-fired steam generator NSPS. The proposed 7-day averaging period was selected by EPA after careful consideration of a range of averaging periods. A daily averaging time was judged by EPA to be too short to account for sampling variability. Also, a daily averaging time would constrain a refiner's flexibility in blending different types of feedstocks for processing in the FCCU. A 7-day averaging time would reduce sampling variability and increase refiner flexibility in selecting the FCCU feedstock mix. However, increasing the averaging time beyond a 7-day period would allow feedstocks with sulfur contents significantly greater than 0.30 weight percent to be processed in the FCCU during a portion of the sampling period. Consequently, a refiner would be able to process high sulfur feedstocks without having to use any SO_X controls. This would be inconsistent with the intent of the standards to apply BDT to control emissions from the regenerator of FCCU's processing feedstocks with more than 0.3 weight percent sulfur. Therefore, EPA selected the 7-day averaging period to allow reasonable flexibility to the refiner for processing different sulfur content feedstocks.

Control Technologies and Economic Impacts

SO_X Scrubbers

Comment (Performance): Some commenters challenged EPA's assessment of the performance of scrubbers as applied to FCCU's. These commenters expressed the opinion that scrubbers should not be considered BDT because they are not demonstrated on high sulfur feeds and have poor operability. Another commenter supported EPA's statements that scrubbers can achieve 90 percent reductions in SO_2 emissions over the expected range of inlet SO_2 concentrations.

Response: Scrubber SO_X control is a function of the scrubbing liquor sorbent and good contact between the SO_X-containing flue gas and the scrubbing liquor. Based on engineering judgment, scrubbers applied to higher SO_X-containing gas streams would be expected to operate as well as those scrubbers applied to lower SO_X-containing gas streams. However, because scrubbers have not been applied to FCCU's processing high sulfur feeds, none was available for testing by EPA to confirm scrubber performance. Therefore, EPA compared the composition of FCCU exhaust gases to industrial boiler flue gases to determine if the performance of sodium scrubbers for industrial boilers is applicable to FCCU's processing high sulfur feedstocks. This comparison showed that the coke formed on the FCCU catalyst is a carbonaceous material similar to the coal used in solid fuel-fired industrial boilers. The catalyst coke is burned off the catalyst during regeneration by adding air to the regenerator. The regeneration process is thus similar to the combustion processes that take place in boilers. Given the similarities between catalyst coke and other solid fuels, the combustion process that takes place in the FCCU regenerator is expected to yield exhaust gases that are similar to those derived from coal-fired boilers. A comparison between FCCU regenerator exhaust gases and industrial boiler flue gases was presented in Table 4–3 in the proposal BID. The comparison showed that the ranges in concentration of most FCCU regenerator exhaust gas constituents (nitrogen (N_2), oxygen (O_2), carbon dioxide (CO_2), SO_X, nitrous oxides (NO_X)) are similar to the boiler flue gas concentrations. Scrubber systems installed on FCCU regenerators will thus experience similar inlet concentrations as boiler scrubber systems.

The primary difference between FCCU regenerator exhaust gases and boiler flue gases is the particulate emissions. Boiler particulate emissions are higher and composed primarily of fly ash. Catalyst fines comprise the majority of regenerator particulate emissions. In an industrial boiler application, fly ash is typically collected upstream of a non-venturi type scrubber. A similar type of scrubber applied to an FCCU would require particulate control upstream from the scrubber. According to scrubber vendors, the particulates that pass through the particulate control device would not affect the design of the scrubber regardless of the application. This is because catalyst fines are no more erosive than fly ash and neither type of particulate would interfere with the scrubbing reaction. Thus, the difference in particulates from an industrial boiler and an FCCU are not expected to affect scrubber performance.

A second, less important difference is that hydrocarbon emissions from FCCU regenerators may be higher than those from boilers. The presence of hydrocarbons in the FCCU gas stream will not affect scrubber operation or performance. Due to the low solubility of hydrocarbons in the aqueous scrubbing liquor, the hydrocarbons will not be absorbed, but will pass through the scrubber to the atmosphere. Other differences in gas compositions are minor and are not expected to invalidate the applicability of scrubber systems for FCCU regenerators.

The similarities in flue gas flow rates and characteristics between industrial boilers and FCCU's and consideration of their differences support the reasonable conclusion that industrial boiler sodium scrubber performance is applicable to FCCU's. The commenter did not provide any information to show that scrubber performance for industrial boilers would be different than scrubber performance for FCCU's.

Source test results for a sodium scrubber applied to an industrial boiler burning a high sulfur fuel show that sodium scrubbers can achieve at least 90 percent reduction in SO_x emissions at high inlet SO_x concentrations. Therefore, in consideration of the above mentioned similarities, EPA has reasonably concluded that the FCCU standard is achievable and that scrubbers are applicable over the expected range of FCCU regenerator exhaust gas sulfur concentrations.

At proposal, sodium scrubbing systems had been effectively applied to seven FCCU regenerators at five refineries to control SO_x emissions. Since proposal, to the Agency's knowledge, two other scrubbers controlling FCCU's at two refineries have begun operation. There is no information to show that the operation of these sodium scrubbers has increased FCCU shutdowns, reduced refinery capacity, or reduced refinery profitability. Rather, the sodium scrubbers applied to FCCU's have operated continuously with no failures between FCCU turnarounds. The commenter provided no data to support his claims that scrubbers have poor operability. Thus, EPA continues to believe scrubbers are an effective control method for reducing FCCU SO_x emissions.

Comment (Water Impacts): Five commenters stated that the waste disposal aspects of the proposed standards are more complex than shown by the analysis presented in the proposal BID. Commenters stated that inland refiners would not be able to obtain a permit for the discharge of waste liquids from sodium scrubbers and would need to install expensive additional wastewater treatment systems to meet permitted discharge levels.

Response: The petroleum refining effluent guidelines (40 CFR Part 419) **Federal Register** technically apply to all wastewater from air pollution control devices when these wastes are treated with the main refinery wastewater or are discharged from the main refinery wastewater treatment system. The costs for the treatment of these wastes are accounted for under the Part 419 regulations. If the scrubber wastes are processed, treated, or discharged separately from the main refinery wastewater collection, treatment, or disposal system, then case-by-case determinations would be made to regulate them. However, the major polluting characteristic of the treated sodium scrubber wastestream is its high dissolved solids content, about 6 percent solids by weight, which consists primarily of sodium sulfates. There are currently no Federal regulations applicable to the dissolved solids content of the sodium scrubber wastestream. Instead, limitations on dissolved solids, where appropriate, would be developed on a case-by-case basis outside of the Federal effluent guidelines. Such limitations should be based on whether the receiving water body can still meet the relevant water quality standard. For many refineries, the sodium scrubber wastewater would constitute a small portion of the total refinery wastewater flow. Thus, the dissolved solids content of the combined scrubber and treated refinery wastestreams may be within permit levels.

All seven sodium scrubbers operating at the time of proposal to control SO_x and particulate emissions from FCCU's are located at coastal locations where no requirements exist for the discharge of sodium scrubber wastes to brackish or salt water. Further, at least one of the two scrubbers applied to FCCU's since proposal discharges to brackish water. However, sodium scrubbers have been used extensively at inland locations to control SO_x emissions from industrial boilers. Waste disposal methods used include discharge to a sewer, discharge to surface water, evaporative ponding, deep-well injection, and recycle. If a refiner elects to install a sodium scrubber but cannot obtain a discharge permit, he will need to use one of these disposal methods. These methods may be costly and have limited availability.

However, other SO_x scrubber systems with minimal wastewater impacts are applicable to FCCU's at a reasonable cost. These include dual alkali and spray drying scrubbers, which have no significant liquid waste but instead produce solid waste. There are also Wellman-Lord and citrate scrubbers, which have no significant liquid waste and produce a salable sulfur product. These scrubbing systems have demonstrated removal efficiencies of 90 percent on industrial boilers. Due to the similarities between industrial boiler and FCCU flue gases, these scrubbing systems are applicable to FCCU's. The costs and cost effectiveness of these scrubbers were evaluated by EPA and are judged to be reasonable. Alternatively, the refiner may choose to demonstrate compliance with the standard for FCCU's without add-on controls by using hydrotreating or SO_x reduction catalysts, or by complying with the feed sulfur cutoff using low sulfur feedstocks.

Comment (Solid Waste Impacts): Two commenters questioned EPA's assessment that sodium scrubbers would have no added cost impacts for solid waste disposal. One commenter asked how EPA determined that sodium scrubber waste is 50 percent water and felt that this increase in weight of total discharge would result in an incremental waste disposal cost "chargeable" to this standard. The other commenter stated that scrubbing systems could greatly increase the amount of solids generated, and thus increase disposal costs, provided disposal locations are available.

Response: The sodium scrubbing systems that are currently applied to FCCU's control both particulate emissions as well as SO_x emissions. With this type of scrubber, an additional particulate control device would not be required to achieve the current particulate standard. Control of FCCU particulate emissions (primarily catalyst fines) by a sodium scrubber does not incrementally increase the dry weight of solid waste over control by a dry particulate control device, such as an ESP. Therefore, the amount of particulate matter collected by the sodium scrubbers are not "chargeable" to the SO_x standards. However, solids collected in a scrubber would be wet and, thus, weigh more and encompass a larger volume. It will cost more to transport and dispose solids collected in a scrubber to a landfill than dry solids. The increase due to the amount of water added to the solids is "chargeable" to the SO_x standards and is included as a solid waste cost (at $20.13/Mg) in the analysis of sodium scrubber costs. In addition, a "liquid waste" disposal cost was added as a conservative estimate of the costs to dispose treated liquid scrubber waste to the sewer (see response to the comment on scrubber costs below).

To determine the additional solid waste disposal cost due to the water contained in settled scrubber solids (sludge), it was necessary to determine the percent solids content of the scrubber solids. However, EPA had no information regarding the water content of the settled particulates (sludge) because none of the settling ponds used for sodium scrubbers applied to FCCU's had been emptied. Instead, EPA had information regarding the solids content of wastes for other scrubbing systems, such as dual alkali scrubbers. For these other systems, the percent of solids in the scrubber waste is higher than that from sodium scrubbers, being typically 60 percent solids. The EPA assumed for cost purposes that the settled sodium scrubber waste would be approximately 50 percent solids, by weight.

Other types of nonregenerable scrubber systems, such as dual alkali, spray drying, or lime/limestone scrubbers, generate greater quantities of solid waste than generated by sodium scrubbers. A dual alkali scrubber controlling SO_x emissions from an FCCU processing a 1.5 weight percent sulfur feedstock will produce approximately 7,700 Mg/yr of solid waste for a 2,500 m^3/stream day (sd) FCCU and 25,000 Mg/yr for an 8,000 m^3/sd FCCU. The EPA considers the solid waste impacts for these systems reasonable. Should solid waste disposal locations not be available, the refiner would need to consider control techniques that do not produce solid waste, such as regenerable scrubber systems (e.g., Wellman-Lord or citrate scrubbers which produce salable sulfur products), hydrotreating, SO_x reduction catalysts, or low sulfur feedstocks.

Comment (Air Impacts): Commenters questioned the appropriateness of using scrubbers if they increase ground-level SO_x concentrations and one commenter suggested that EPA require reheating the scrubber exit gases to reduce ground-level concentrations and to include reheat in the sodium scrubber cost analysis.

Response: Scrubbing a gas stream lowers the temperature of the gas stream. Unless the gas stream is reheated downstream of the scrubber, the plume emitted from the scrubber stack will be cooler than the plume emitted from an FCCU regenerator not using a scrubber. Lowering the temperature of the plume reduces the effective height above the ground to which the plume will rise.

The results of dispersion modeling performed by EPA and presented in the proposal BID were used to analyze the air quality impact of the proposed standards. In all cases ground level SO_x concentrations are within the national ambient air quality standards. For all the model plant scenarios except the one processing a low sulfur feedstock, the ground level SO_x concentrations predicted for implementation of the proposed standards are lower than the baseline (uncontrolled) concentrations. In these cases, the decrease in SO_x emissions afforded by implementation of scrubbers offsets the lower plume rise.

The EPA agrees that if a control technique other than a scrubber was used to achieve the same emission reduction as the scrubber would achieve, the resulting maximum ground level concentrations may be less than if a scrubber were used. However, the application of SO_x reduction catalysts to meet the standard for FCCU's without add-on controls would provide less emission reduction than the application of scrubbers. The additional emission reduction provided by scrubbers would likely compensate for the lower plume rise, so that the use of scrubbers would result in lower ground-level concentrations than the use of SO_x reduction catalysts.

The stack temperatures, heights, and exit velocities used in the modeling analysis were selected as average values from data for actual FCCU scrubbers. Only one of the seven FCCU sodium scrubber installations existing at proposal is equipped with scrubber stack reheat. Reheat is used only occasionally to reduce the visible steam plume during certain weather conditions. For this reason, EPA believes that the modeling input parameters selected and the assumption of no reheat are appropriate.

Comment (Scrubber Costs): Five commenters stated the opinion that the scrubber costs presented in the proposal BID are unrealistic and are significantly underestimated. The commenters claimed that the scrubber cost estimates should be 2.2 to 7 times higher. The commenter's specific comments are identified in the response below.

Response: To respond to these comments, EPA decided first to solicit more detailed cost data for single alkali scrubbers from vendors and then to perform a general reevaluation of the cost data presented in the proposal BID. Concurrently, EPA solicited supplemental cost data from commenters and then addressed the individual comments pertaining to specific cost items.

A. *General Cost Review.* First, EPA solicited data from scrubber vendors other than the vendor who provided the costs on which the proposal BID cost estimates were based. This vendor is the only one whose scrubber has actually been installed on an FCCU. The EPA received detailed cost data from two other scrubber vendors, one of which has served as a subcontractor to the primary vendor in the installation of several of their scrubbers on FCCU's, and, therefore, is familiar with FCCU operation, refinery codes, and equipment specifications. The other vendor that supplied cost data has considerable experience with the design and application of scrubbers to industrial boilers, but not to FCCU's.

The analysis of these data showed that the costs provided by the primary vendor of single alkali scrubbers applied to FCCU's, were the highest of all the vendor cost estimates and are conservative due to more stringent design specifications than other vendors use and the use of redundant equipment that serve to provide the scrubber with the reliability that petroleum companies believe is necessary in the refining industry. In particular, the primary vendor's system design specifications call for vessel design coded by the American Society of Mechanical Engineers (ASME), and design of pumps, piping, and electrical equipment coded by the American Petroleum Institute (API); one of the other two vendors that provided cost data did not specify such coded design. Vessels on scrubbers designed by the primary vendor are larger than those designed by the other two companies, and use special refractory linings to protect the steel shell from the abrasive effects of catalyst fines in the refinery flue gas. Further, the primary vendor's design requires sparing of all rotating equipment and critical analyzers, and specifies multiple venturis, rather than a single variable throat venturi as specified by the other vendors. Fluid catalytic cracking units may be in continuous operation for about 3 years nonstop, or significantly longer in some cases, and the primary vendor designs their scrubbers to maintain safe and reliable operation for time periods equal to that of the FCCU's the scrubbers control.

B. *Review of Specific Cost Comments.* Second, EPA considered the specific cost comments provided by companies.

One commenter stated that EPA's costs were low, in part, because of erroneous assumptions of FCCU exhaust gas volumes. The EPA concluded that the exhaust gas volumes used for the cost analysis for FCCU's using HTR are appropriate. Model plant FCCU exhaust gas volumes were developed based on stoichiometric relationships between the coke composition, the amount of air necessary to burn the coke, and typical levels of excess air. The calculated exhaust gas volumes were compared to actual exhaust volumes reported for FCCU regenerators and were found to be reasonable. Furthermore, the values used for the model plant regenerator exhaust gas volumes were sent to industry representatives for review prior to beginning the impact analyses, and no comments were received by EPA indicating that the exhaust gas volumes were not representative of actual conditions.

During these cost evaluations, EPA revised the exhaust gas volume for FCCU's operating with jet ejector venturis (JEV's) to include the flue gas contribution from the CO boiler. As a result, EPA also revised the capital and annual costs for JEV scrubbers installed on FCCU's. Fluid catalytic cracking units using CO boilers must install the JEV-type scrubber. The JEV costs presented in the proposal BID did not account for the additional flue gas volume that would enter a JEV scrubber because of the combustion air required in the CO boiler. The EPA determined that flue gas volume to a JEV scrubber would be about 10 percent higher than the volume of gas from an FCCU to a high-energy venturi scrubber. This increased volume resulted in about a 3-percent increase in the cost of the JEV scrubber over that previously calculated.

Several commenters stated that EPA used erroneous assumptions for scrubber waste disposal costs. The EPA, therefore, reviewed the waste disposal costs used in the proposal BID. The cost values used in the proposal BID represent the cost for the transport to and disposal of collected catalyst fines in a landfill. This solid waste disposal cost is based only on the additional mass of solid wastes to be disposed due to the use of a wet scrubber as the collection device instead of an ESP. In the proposal BID, no costs were credited to the disposal of the treated liquid wastes because EPA assumed that the treated liquid wastes were disposed to surface water. Upon review, EPA decided that it is appropriate to provide a more conservative estimate of liquid waste disposal costs by assuming that all affected facilities would discharge to sewers. Some refiners, especially in coastal locations, will likely be able to discharge the treated scrubber liquid wastes to surface waters without incurring a sewer discharge cost.

Two commenters questioned EPA's assumptions of off-site costs. Two other commenters stated that EPA did not consider site space or equipment variability, soil conditions, FCCU turnaround schedule, start up costs, or construction climate. The EPA has considered specific costs for off-sites, soil conditions, turnaround schedule, equipment availability, climate, and startup in the costs estimates. Off-sites include electricity, water, fire protection, steam, compressed air, and other utilities. The scrubber costs used by EPA to evaluate cost impacts include the cost of connecting utilities to the scrubber provided the utilities are located within the battery limits of the FCCU. The battery limits refer to that portion of the refinery associated with a particular process unit and its supporting equipment. Where utilities are not available or insufficient capacity is available within the FCCU battery limits, the refiner will incur a cost greater than that assumed in the cost estimates. However, a 20-percent contingency is provided in each capital cost estimate. The EPA considers the site-specific costs related to soil conditions, turnaround schedules, site space and equipment availability, climate, startup, and the expense of off-sites to be included in this contingency and, therefore, to have been considered by EPA.

In support of the comments on costs of construction climate, space and equipment availability, and pond and treatment system requirements, one commenter provided capital costs for the retrofit installation of a sodium scrubber to control both particulate and SO_x emissions from an FCCU at an existing refinery. The single alkali scrubber is sized for a flue gas volumetric flow rate similar to the 8,000 m^3/sd model plant used by EPA in developing costs. A comparison of the commenter's cost estimate with EPA's revised cost estimate shows that the total direct cost for both estimates is about the same. The commenter applied a 60-percent factor to account for indirect costs compared to the 40-percent factor used by EPA. The commenter also applied to this base cost estimate an additional 27-percent cost adjustment, which included labor productivity, design allowance, and construction climate. The EPA evaluated the commenter's cost factors and believes that these factors are adequately accounted for by EPA's 20-percent contingency cost factor. When adjusted to equivalent dollars, the commenter's cost estimate is approximately 50 percent higher than EPA's revised cost estimate for a single alkali scrubber of a comparable size installed on an existing FCCU.

The commenter's scrubber costs were developed from a preliminary factor-type cost estimate provided by a vendor. This type of cost estimate is developed in the early stages of a construction project when the project specifications are not very well defined. A factor-type estimate will typically contain several generous cost allowances to account for uncertainties in equipment specifications and construction. As a project becomes more defined, the final cost estimate normally is lower, and closer to the actual cost of the project. The EPA's costs are based on a vendor's experience with scrubber applications to FCCU's, and EPA believes that these costs are more representative of the actual cost of this scrubber design than the cost estimate provided by the commenter. Thus, the difference between the commenter's cost estimate and EPA's revised costs is largely due to the preliminary nature of the commenter's cost estimate.

One commenter indicated that EPA's cost estimates should more appropriately be based on the use of dual alkali flue gas desulfurization systems, because single alkali systems may not be applicable in areas where water availability or wastewater discharge is restricted. The commenter provided cost data to show that dual alkali systems are more expensive than single alkali systems. A dual alkali scrubber consists of two parts, the "front half" and the "back half." The front half of a dual alkali scrubber resembles a single alkali scrubber without a wastewater treatment unit and performs the same function—removing SO_x from a gas stream by contacting it with a caustic or soda ash scrubbing liquor. In the back half of a dual alkali scrubber, however, the purge is treated to regenerate the scrubbing liquor for reuse; a single alkali scrubber simply treats and discharges the purged liquor.

The EPA agrees that, where direct discharge of scrubber wastewater is not permitted, dual alkali scrubbers would be a viable alternative to single alkali scrubbers because dual alkali scrubbers produce a calcium sulfate sludge that would be more readily disposed than wastewater, but disagrees that dual alkali scrubbing systems would be more expensive than single alkali.

The commenter compared capital costs for dual alkali scrubbers to EPA's proposed single alkali scrubber costs. The commenter's cost estimates were based on proprietary actual scrubber cost information provided by the commenter's contractors. For each of the model plants presented in the proposal BID, a computer cost model was used by the commenter to estimate dual alkali scrubber costs assuming 90 percent SO_x reduction. The commenter's dual alkali scrubber costs are a function of volumetric gas flow rates and sulfur loading. The commenters cost estimates for dual alkali scrubbing were significantly higher than EPA's proposal estimates for all dual alkali model units.

Because these differences existed, EPA performed a further evaluation of dual alkali costs based on data from vendors of dual alkali systems. Specifically, costs from the primary vendor of single alkali scrubbers to FCCU's were used to develop costs for the front half of both sizes of a dual alkali scrubber. Another vendor provided back half costs for both sizes of dual alkali scrubber. The primary vendor also provided EPA with a cost estimate provided to them by an independent vendor of dual alkali scrubbers for the back half of a dual alkali scrubber applied to the 8000 m^3/sd FCCU only. The commenter's and EPA's costs are based on a scrubber design that would control both FCCU particulate and SO_x emissions.

The EPA's revised capital cost estimates for dual alkali scrubbers are greater than those in the proposal BID, but less than the capital cost estimates for single alkali scrubbers provided by the primary vendor. This is because the back half of the dual alkali scrubber, where the purged scrubbing liquor is treated to regenerate it for reuse, was found to be less costly than the wastewater treatment system needed to treat the purged scrubbing liquor before discharge from a single alkali system. Construction costs for the in-ground ponds specified by the primary vendor for wastewater treatment are greater than the cost of the dual alkali sludge dewatering and disposal facilities.

A comparison of EPA's revised dual alkali costs with those provided by the commenter shows that the commenter's total dual alkali costs remained significantly higher than EPA's revised dual alkali total cost estimate. However, because the commenter's cost information is based on proprietary actual cost data developed by contractors of dual alkali scrubbers and provided to the commenter, detailed cost information was not provided to EPA by the commenter, and a comparison of EPA's individual capital costs to those provided by the commenter was not possible.

The EPA's analysis of data supplied by vendors of dual alkali systems indicates that total single alkali scrubber costs are more costly than total dual alkali scrubber costs rather than less costly as the commenter believes. Therefore, EPA's current cost estimates for model plants, which reflect the use of only single alkali scrubbing, represent a conservative estimate of nationwide costs; dual alkali cost estimates applied to the model plants would only decrease the national costs. Therefore, it was decided not to revise costs of SO_2 control of model plants to reflect the use of dual alkali at some facilities.

This commenter also provided cost data for single alkali systems. The EPA performed an analysis of this single alkali cost data for comparison to single alkali cost estimates in the proposal BID. The commenter's costs for single alkali scrubber systems are similar to EPA's revised costs for the low sulfur model plants, but are significantly higher than EPA's revised costs for the 1.5 and 3.5 weight percent sulfur model plants. The commenter's single alkali cost estimates assume that single alkali capital costs are 93 percent of dual alkali costs. The EPA believes this approach is inappropriate because, whereas capital costs for dual alkali systems are a function of both waste gas flow rate and feed sulfur content, capital costs for single alkali systems are a function only of waste gas flow rate. Dual alkali control requires equipment to regenerate the reagent solution, the cost of which depends, in part, on the sulfur content of the flue gas. Because single alkali systems do not have such equipment, capital costs of single alkali control are a function only of waste gas flow rate. Therefore, single alkali cost estimates derived by applying a constant percentage of dual alkali costs for different sulfur content models would result in erroneous estimates. The EPA believes, therefore, that the accuracy of the commenter's single alkali costs, which increase with feed sulfur content, is doubtful.

Two commenters stated that EPA needed to reevaluate the cost of retrofitting existing FCCU's with scrubbers. The EPA reevaluated these costs. Costs associated with retrofit will vary widely from one refinery to another based on the refinery configuration and the availability of land. In some cases, space limitations around an existing FCCU may result in relocating utilities and piping runs, longer ducting runs, and other factors that may make scrubber installations more difficult than at a new refinery. Therefore, EPA agrees that retrofit should be included in the cost estimates for some model plants. A retrofit cost factor of 20 percent of the scrubber capital cost (less contingency) was estimated by one commenter. This cost was added to three of the seven modified or reconstructed FCCU's anticipated to be subject to this standard during the first 5 years after the effective date of the standard.

One commenter stated that EPA did not consider a cost for business interruption that would result from a scrubber malfunction shutting down the FCCU. Although sodium scrubbers have demonstrated reliability factors in excess of 95 percent, scrubber malfunctions can occur. The General Provisions to 40 CFR part 60 states that emissions in excess of an emission limit during a period of malfunction of a control device are not considered a violation provided the control device has been properly operated and maintained. During a period of a sudden or unavoidable scrubber failure, the refiner would still be able to operate the FCCU. Therefore, no business interruption cost would be incurred. For this reason, EPA did not include a business interruption impact when revising the proposal BID costs.

One commenter stated that EPA subtracted an ESP cost credit inappropriately in the cases of an existing FCCU with an ESP in place if scrubbers are required as a result of modification/reconstruction. The EPA agrees that an ESP cost credit is not appropriate in these cases. The proposal BID costs were revised to eliminate the ESP cost credit for the three modified or reconstructed FCCU's in which retrofit costs were included.

C. *Summary of Cost Changes.* As a result of both the general reevaluation of costs and the review of specific cost comments, EPA revised the capital and annual cost estimates for FCCU scrubbers. The following changes were made: (1) Costs of individual components were adjusted based on the data received; (2) JEV scrubber costs were revised to account for increased flue gas volume entering the scrubber as a result of CO boiler combustion air; (3) waste disposal costs were increased to include liquid waste discharges; (4) a cost for retrofit installation was added for the modified or reconstructed FCCU's; and (5) the ESP cost credit was deleted for the three scrubbers that were installed on modified or reconstructed FCCU's and for which retrofit costs were included. Costs were then further adjusted to 1984 dollars.

After both the general and the specific cost analyses, EPA concluded that the proposal BID costs are not understated by a factor of 2.2 to 7. Changes in cost as described above caused nationwide capital costs to increase by 30 percent (from $72 to $93.6 million); adjusted to 1984 dollars, capital costs increased a total of 63 percent from proposal (from $72 to $117 million). Changes in cost caused nationwide annual costs to increase by 5 percent (from $35 to $36.6 million per year); adjusted to 1984 dollars, annual costs increased a total of 29 percent from proposal (from $35 to $45 million per year).

Thus, these estimates show that the standards would result in a total nationwide capital cost for SO_x control for the first 5 years after the effective date of the standards of $117 million, assuming sodium-based scrubbers are used at all facilities processing feedstocks with sulfur content above 0.3 weight percent. The fifth year nationwide annual cost is $45 million. Units processing feedstocks with sulfur contents of 0.3 weight percent would be below the feed sulfur cutoff and, therefore, would not need to install a scrubber. Where sodium scrubbers are not applicable, dual alkali scrubbers could be used at a similar cost to sodium scrubbers.

SO_x Reduction Catalysts

Comment (Performance): Commenters stated that SO_x reduction catalysts are not demonstrated and cannot achieve 80 percent reductions in SO_x emissions.

Response: The EPA considers SO_x reduction catalysts to be an emerging technology. The standards allow for their use and thereby encourage their further development. Current catalysts show promising results. As described in the "Level of Standards" section of this preamble, current SO_x reduction catalysts can achieve SO_x emission reductions of 65 to 75 percent. Additionally, for many feed sulfur levels, the standard can be met with less than 80 percent SO_x emission reduction.

Comment (Solid Waste Impacts): One commenter stated that, according to the preamble, SO reduction catalysts are not expected to have a solid waste impact. The commenter estimated, however, that the use of SO_x reduction catalysts would increase FCCU solid waste by 11,000 Mg/yr.

Response: The EPA does not believe that the use of SO_x reduction catalysts would result in a significant increase in FCCU solid waste. When used as an additive, SO_x reduction catalysts replace from less than 5 to 10 percent of the circulating catalyst inventory. One of the catalyst developers stated that, due to the softness of their SO_x reduction catalyst (an additive), its makeup rate is greater than that for the cracking catalyst. The developer reported that this may result in an increase in solid waste of up to 40 percent. Based on recent tests by another developer, solid waste increases of less than 5 percent are anticipated for the newer SO_x reduction catalyst formulations because these are much harder than earlier formulations. The EPA believes that it would be in the catalyst developers' interest to produce a harder reduction catalyst because a harder formulation would have a lower makeup rate and therefore, most likely would cost less to use than a softer one. Other recently developed catalyst formulations incorporate the SO_x reduction catalyst as a constituent of the cracking catalyst and consequently, SO_x control can be accomplished without increasing the total quantity of cracking catalyst used in the FCCU over a period of time. In this case, SO_x reduction catalysts would not increase particulate emissions or solid waste. In summary, whether the SO_x reduction catalyst is in the form of an additive or a constituent of the cracking catalyst, it is unlikely that the use of newer SO_x reduction catalyst formulations would significantly increase FCCU solid waste over current levels.

Comment (Air Impacts): One commenter stated that the preamble to the proposed standards does not adequately address the effect of SO_x reduction catalysts on NO_x emissions. The commenter pointed out that the preamble states that SO_x reduction catalysts would not increase NO_x emissions, while the proposal BID and a docket entry show that SO_x reduction catalysts raised NO_x emissions.

Response: Most refiners use one of two techniques to control CO emissions from the FCCU regenerators: HTR or catalytically promoted CO combustion. Data from some tests of NO_x emissions from regenerators using both CO combustion promoter catalysts and SO_x reduction catalysts in combination show an increase in NO_x emissions. Separate data for regenerators using CO combustion promoters without SO_x reduction catalysts suggest that the use of these catalysts may increase NO_x emissions. Thus, at this time, it is unclear whether the NO_x increases observed for SO_x reduction catalyst tests are due to the reduction catalyst or the CO combustion promoter. Recent commercial tests of SO_x reduction catalysts in FCCU's utilizing HTR show no increase in NO_x emissions. No recent tests of SO_x reduction catalysts in FCCU's utilizing CO promoters were available. Because most FCCU's subject to the standards are expected to use HTR and because newer SO_x reduction catalyst formulations have not increased NO_x emissions, EPA believes that the use of the SO_x reduction catalyst technology will not increase NO_x emissions.

Comment (Costs): Three commenters wrote that in certain circumstances the SO_x reduction catalyst technology requires a capital outlay. The circumstances identified by the commenters were: (1) Because SO_x reduction catalysts can only be used in units with HTR, older units subject to the standards under the modification or reconstruction provisions that do not or cannot operate in this mode will be required to convert or modify units; (2) small refineries that do not have sulfur recovery units; and (3) refineries with inadequate sulfur recovery unit capacities to handle the increased sulfur load due to the SO_x reduction catalyst technology. In addition, two commenters stated that annual costs for SO_x reduction catalysts will likely be at least 2 times higher than EPA's estimate.

Response: Many refiners have modified their older FCCU's to HTR; HTR offers advantages over conventional regeneration (e.g., reduced SO_x emissions, improved yields, and increased throughput). It is unlikely that an older FCCU would become subject to these standards through the modification/reconstruction provisions without modifying the unit to HTR. A refiner is more likely to use SO_x reduction catalysts in an FCCU modified for HTR than to modify an FCCU solely to use SO_x reduction catalysts. If an

FCCU subject to these standards cannot utilize SO_x reduction catalysts, the refiner is more likely to select another control technique than incur a $10–20 million capital expenditure.

Use of SO_x reduction catalysts will increase the amount of hydrogen sulfide (H_2S) in refinery fuel gas, which is removed from the fuel gas in a sulfur recovery unit. The increase in the amount of H_2S to a sulfur recovery unit is only about 5 to 10 percent. Sulfur recovery units generally are overdesigned by much more than this to account for swings or surges in H_2S production from refinery process units. It is doubtful that the use of SO_x reduction catalysts alone would overload a sulfur recovery unit.

The EPA contacted companies developing or licensing SO_x reduction catalysts to obtain current costs for commercially available SO_x reduction catalysts. Catalyst developers reported costs for the technology ranging from $0.60 to $1.60 per cubic meter of fresh feed processed. The fifth year cost for SO_x reduction catalysts was then calculated by multiplying the cost factors provided by the catalyst developers by the total fifth year annual throughput for all affected facilities processing feedstocks containing greater than 0.30 weight percent sulfur. The new fifth year cost for SO_x reduction catalysts ranges from $20 million to $50 million. Costs for SO_x reduction catalyst are presented as a range because the technology is under development. The upper end of the range represents a newer catalyst formulation; the developer of this catalyst expects the cost to decrease as the catalyst formulation is produced in greater quantities.

Economic Impacts

Comment: Several commenters stated that the proposed standards would have an adverse effect on the refining industry and the nation's economy. Four commenters wrote that the compliance costs are sufficiently high to require the preparation of a Regulatory Impact Analysis under Executive Order 12291. One commenter wrote that current prices will reduce the attractiveness of FCCU modifications to the point where the additional cost of a scrubber or other SO_x control device would not be feasible. Three commenters wrote that the costs of the proposed standards would, in some cases, postpone new investments and would cause a significant economic impact on the profitability of FCCU operation and the construction of new FCCU's.

Response: The cost analysis presented in the proposal BID was reviewed under Executive Order 12291 by the Office of Management and Budget (OMB). Since that time, in response to comments, EPA has revised these costs upward. With these revisions, the fifth year nationwide annualized costs are still below the $100 million level that triggers a regulatory impact analysis under Executive Order 12291. The price increases published in the proposal BID were all less than 0.4 percent. Using the revised control costs and second quarter 1984 product prices, that figure increases to approximately 0.8 percent for the worst case considered (3.5 weight percent sulfur feedstock). The EPA still considers this to be acceptable.

The capital required for the control devices will increase the investment for a new FCCU by 9 percent for the 8,000 m^3/sd unit and by 15 percent for the 2,500 m^3/sd unit. The EPA does not consider these percentages sufficiently high to deter a decision to install an FCCU that is otherwise economically justified.

Compliance Testing and Monitoring

General

Comment: Two commenters pointed out that as proposed SO_x testing would be conducted upstream of the CO incinerator while velocity and volumetric flow rates would be determined downstream of the CO incinerator. One commenter pointed out that the regulation indicates that sampling for SO_x concentration "shall be the same as for determining volumetric flow rate;" the commenter believed the regulation statement is correct. One commenter stated that it is unsafe to require personnel to conduct manual sampling due to the high flue gas temperatures at this location (650–769 °C) and that sampling at extreme temperatures is impractical due to frequent sampling train operating problems and rapid sample probe failures.

Response: The EPA agrees that SO_x testing should be performed at the same location as the volumetric flow rate measurement, as is specified in the regulation.

The EPA recognizes the commenter's concern regarding safety. Sampling either upstream or downstream from the CO boiler is acceptable for the standard without add-on controls. However, if the owner or operator chooses to test downstream of the CO boiler, alternative calculation procedures for determining the coke burn-off rate and the SO_x contribution due to the auxiliary fuel burned in the boiler must be submitted to and approved by the Administrator. In addition, the recommended location for the inlet CEMS has been changed to downstream of the CO boiler for the standard with add-on controls.

Add-On Control Devices

Comment: One commenter stated that an operator of an add-on control device should be given the flexibility to choose between the original proposal, which would have required using an outlet monitor only, and the operation of a CEMS in which both an inlet and outlet monitor are used.

Another commenter stated that after the compliance test, the proposed standards only need an "alerting service," which could be provided by an outlet monitor alone.

Response: The standard for FCCU's using add-on controls is 90 percent reduction or 50 vppm, whichever is less stringent. The intent of monitoring for the standard for add-on controls is to determine compliance on a daily basis, as described in the revised proposal. To meet this intent, the Agency needs data that show the actual compliance status of the source, not data that simply alert the Agency to potential problems. To make an accurate determination of compliance with the 90 percent reduction standard, the Agency must have both scrubber inlet and outlet data. Even where feed sulfur is not "highly" variable, the outlet concentration may vary due to FCCU operation or the source of the feed, while scrubber performance may stay constant. Therefore, measuring only the outlet emissions may lead to an incorrect compliance determination for the percent reduction standard. The Agency recognizes, however, that an inlet monitor is unnecessary for making continuous compliance determinations in relation to the 50 vppm standard for add-on controls. Thus, the Agency has modified the regulation so that owners or operators may choose to declare their intent to meet the standard for add-on controls by limiting their outlet SO_2 emissions to 50 vppm and install a CEMS at only the outlet of the control device to determine compliance. The Agency wishes to point out that, for such owners or operators, compliance determinations will be made only on the basis of the outlet SO_2 emissions without regard for the percent reduction being achieved by the control device. Such owners or operators may change their choice so they would be subject to the whole standard on "90 percent reduction or 50 vppm, whichever is less stringent," provided a CEMS is installed and maintained at the inlet of the control device as well as the outlet.

Comment: One commenter felt that because an add-on control device achieves greater reductions in SO_2 emissions than technologies meeting the standard without add-on controls, "less drastic" compliance monitoring requirements for scrubbers are reasonable. This commenter proposed that compliance be determined instead by an initial performance test, quarterly monitoring of inlet and outlet SO_x concentration using EPA Reference Method 6 or 6B, and continuous monitoring of wet gas scrubber process variables, such as pH, liquid-to-gas ratios, and pressure drop, to evaluate scrubber performance in an ongoing basis.

Response: Monitoring and testing requirements are chosen to be appropriate for the control technique and to meet the intent or goal of the monitoring and testing. The relative stringency of different control techniques has no bearing on the selection of the most appropriate monitoring or testing requirement for each control technique.

The purpose of monitoring for these standards is determining compliance on a daily basis. The procedure suggested by the commenter does not give information from which the compliance status can be determined daily.

Comment: Several commenters stated that continuous SO_2 monitors are unreliable due to monitor operational problems. One commenter proposed that the requirement for continuous monitoring of the inlet and outlet to add-on controls be eliminated, while another commenter recommended an increased allowance for CEMS downtime and maintenance, such as requiring data for 15 days per month instead of 22, and 12 hours per day instead of 18. One commenter stated that, to his knowledge, EPA does not have CEMS data showing that the device can run 24 hours per day for one full month and give accurate results. He also asked about the frequency of manual emission testing that would be required when the CEMS fails.

Response: The EPA extensively studied the reliability of SO_2 and diluent CEMS during the development of subpart D, subpart Da, and appendix F of 40 CFR part 60. Current studies show that state-of-the-art monitoring systems provide precise and accurate data when proper operation and maintenance techniques are employed on a continuous basis. Experience has shown that approximately 2 hours per day of manual attention is necessary to obtain an 85 percent or greater availability. Further, as discussed in the BID for the proposed standards, Appendix D, FCCU catalyst regenerator exhausts are similar to those of coal-fired steam generators; therefore, the continuous SO_2 monitoring technology proven acceptable for steam generators should be applicable to FCCU catalyst regenerators. The SO_2 monitors have been installed on some FCCU catalyst regenerators; EPA has gathered information on the operational history of some of these CEMS but the data were insufficient to compare directly to appendix F to 40 CFR part 60, which contains quality assurance procedures for CEMS used for compliance determinations.

The Agency has, for example, conducted tests at a sodium scrubber on an FCCU using inlet and outlet SO_2 CEMS. The outlet monitor was on a saturated gas stream without reheat of the flue gas. There was no particulate removal in the flue gas prior to the inlet monitor. The duration of the testing was about 12 days. Over this time, no difficulty was experienced in obtaining valid data. Some regular backflushing of the outlet analyzer system occurred due to the saturated nature of the flue gas. This limited time testing suggests that with careful maintenance of the monitors, long term use and potential problems can be avoided. The difficulty stated with regard to outlet monitors on a saturated gas stream can be overcome through adequate design and maintenance of the CEMS. (The commenter does not state that the difficulty cannot be overcome, but rather just that it is difficult.)

A particular concern of several commenters was particulate plugging. The Agency does not agree that particulate plugging will be a problem if the monitor is properly designed and operated. In-stack filters have been redesigned with better shields, and improved outside-stack conditioning systems have been developed that allow removal of the in-stack filter, when necessary. Furthermore, technologies are available to circumvent CEMS plugging. Properly designed systems usually have back-purge capabilities to prevent particulate plugging of the sampling probe in the stack. Studies have also shown that high pressure (greater than 70 psi) air in backflushing sample lines and probes improves removal of particulate and moisture from the in-stack probes and filters both upstream and downstream of scrubbers. Manufacturers of the systems and installation personnel would be responsible for designing each system for a specific source.

Based on these studies, EPA has concluded that continuous SO_2 monitors are reliable and accurate when properly operated and maintained, and are capable of meeting the minimum requirements for determining compliance with these standards. Thus, the promulgated standards retain the requirement for continuous SO_2 monitors.

The EPA does not expect the CEMS to run nonstop for 24 hours per day for an entire month. To allow for periods when CEM's are shut down for various reasons, minimum data requirements were established. The EPA based its selection of 18 hours of data in a 24-hour day and 22 days of data out of 30 days on the minimum data requirements for compliance determinations specified for utility boilers under subpart Da of 40 CFR part 60. Under these standards, EPA concluded that the required data to be collected provided sufficient information to characterize emissions, and that properly operated and maintained CEMS's were capable of meeting these requirements. The operating conditions at the upstream CEMS at FCCU's are similar to those found at a subpart Da boiler CEMS prior to the flue gas scrubber. The minimum data requirements (i.e., collection of 18 valid hours of data per day for 22 days out of every 30) provide for downtime enabling the owner or operator to maintain and calibrate the CEMS and correct minor malfunctions.

Manual testing is not required when the CEMS fails provided the facility meets the minimum data requirements. Malfunctions are not likely to occur every 30-day period. Thus, EPA expects that most CEMS's routinely will operate better than the minimum data requirements and supplemental sampling will be rarely necessary to meet them.

Many methods are available for supplemental sampling; each owner or operator would develop an approach to obtaining these minimum data in the Quality Control Plan required by Procedure 1 of 40 CFR part 60 appendix F. Any acceptable sampling scheme would have to obtain data representing at least 18 hours of operation daily. If Method 6 is used, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dry standard cubic meters (dscm) (0.71 dry standard cubic feet (dscf)) for each sample. Samples are taken at approximately 60-minute intervals; each sample represents a 1-hour average. To obtain one valid day from supplemental sampling requires 18 valid samples. Method 6B, if used, would also have to collect a sample representing a minimum of 18 hours. If a back-up monitor is used instead, then a minimum of 18 valid hours to obtain a valid day is still required.

Comment: Two commenters questioned the costs of CEMS's reported by EPA. One commenter asked whether the sample collecting and conditioning systems needed to ensure a reliable CEMS were included in the price of the CEMS and whether the Agency updated the costs from the original proposal. The other commenter felt the Agency substantially underestimated the costs of a CEMS.

Response: The cost of the additional CEMS reported in the revised proposal notice reflected the cost of an extractive analyzer and installation (in February 1981 dollars). The Agency updated the original 1981 costs for the extractive analyzer system and obtained a revised fourth quarter 1984 cost estimate of $69,300 (including installation and data acquisition system (DAS); $46,200 without the DAS).

The Agency also recently attempted to obtain updated CEMS cost data by contacting vendors and source owners or operators using CEMS. The study found total worst-case costs for an extractive analyzer (including a DAS and installation) to be from $45,000 to $180,000 (1984 dollars). (The worst-case costs included additional costs for longer sample lines, corrosion-resistant probes, probe back-flush systems, and computer data acquisition systems capable of generating emissions reports.) The commenter provides an estimate of about $100,000 (analyzer, sampling system, and installation). Taking out the cost of a DAS (about $23,000) from the worst-case costs, the commenter's estimate falls in the middle-to-upper end of the worst-case costs. The Agency notes that its original cost estimate for an extractive analyzer, when updated to 1984 dollars, still falls within the worst-case costs range reported in the updated study.

Updating the across-the-stack cost estimate, which was for a complete outlet monitoring system, to fourth quarter 1984 dollars yields a cost estimate of about $92,900 for the analyzer, DAS, and installation. Data on across-the-stack CEMS gathered more recently show total worst-case vendor costs without a DAS from $22,000 to $152,000 (1984 dollars). The one commenter estimated costs of about $150,000 to $175,000 per analyzer (analyzer, sampling, and installation), which falls at the upper range of the worst-case vendor estimates.

The annual maintenance costs estimated by the Agency in the proposal BID appendix D were $11,000 for either an extractive or across-the-stack CEMS. Updating the cost results in an estimate similar to the commenter's estimate of $16,000 for an extractive system and is more conservative than the commenter's estimate for an across-the-stack system.

Without Add-On Control Devices

Comment: Several commenters stated that EPA had underestimated the costs of daily Method 8 testing. Commenters estimates ranged from $184,000 to $400,000/yr per FCCU. Commenters did not think it was reasonable to claim the costs to be "reasonable" when the costs are based, in part, on a traversing system not yet developed. One commenter believed that insufficient qualified contractor manpower exists to conduct the Method 8 compliance sampling.

Response: The EPA agrees with the commenters that the assumption of an automatic traversing system should not be used for evaluating and recommending daily Method 8 testing, although the Agency still contends that it is technologically feasible. Instead, the Agency has revised the cost estimate assuming that a monorail system will be installed at each of the two sampling ports and that a single sampling train will be used, with manual movement of the sampling train for traversing and changing ports. Although not addressed by the commenters, EPA decided that it was appropriate to also include a cost for an enclosed sampling area to protect the sampler and equipment from various weather conditions, such as rain and snow. The capital cost of the monorail system and enclosure is estimated to be $20,000. When the Agency originally estimated the cost using an automated traversing system, two sampling trains were assumed, one in each port. With the revised assumptions, only one sampling train is used, and is moved from one port to the next. The standard requires one 3-hour sample per day, 365 days per year; this halves the number of samples to be analyzed to 365 (1 per day).

The EPA disagrees with the commenters' claim that three or more people would be devoted full-time to this stack testing. Only one 3-hour sample is required each day. The Agency believes that it would take an average of 8 labor hours per day to prepare the equipment, conduct the sampling, and perform periodic maintenance on spare equipment, with added labor for analysis of about 1.3 hours per sample. The revised annualized cost per affected facility is estimated to be $120,000.

The EPA assumed that in-house personnel would be used to conduct the Method 8 compliance sampling. The EPA believes there is sufficient lead time to train such personnel without requiring or solely relying on contractor manpower.

Comment: Many commenters stated that daily testing should be deleted from the standard for FCCU's without add-on controls. The commenters felt that daily testing was too costly and unduly burdensome, especially, according to one commenter, when compared to the costs of monitoring for the scrubber or testing under the feed sulfur cutoff. One commenter stated that the cost of daily Method 8 testing could hamper improvements in SO_x reduction catalyst development.

Response: The Agency recognizes that daily testing with Method 8 is not inexpensive, but that it is also not an unreasonable cost. The Agency has examined various methods available to show daily compliance with the standards. For facilities that opt to use SO_x reduction catalysts to meet the standards, the Agency has determined that daily Method 8 testing is currently the only viable alternative that enables the Agency to be sure that the owner or operator is in compliance on a daily basis.

The relative costs of the various methods for determining continuous compliance available to all affected facilities subject to the standards is not a valid basis for rejecting one method or another. What is relevant is whether the total (capital, annual, monitoring, etc.) cost of compliance for meeting the standards for an affected facility is reasonable or unreasonable. Daily testing is needed for this standard in order to show daily compliance, and the cost of such testing, in the Agency's assessment, is reasonable.

The Agency disagrees that daily testing is too costly and unduly burdensome. The Agency studied the potential economic impact of the standards on small and large refineries and reported and discussed the findings in the original proposal notice to these standards (49 FR 2072). The economic impact to the small (and large) refiner is expected to be small because most, if not all, of the cost should be capable of being included in the prices of the refined petroleum products and the resulting price impact is reasonable. These results were obtained assuming compliance by all projected affected facilities with the standard for FCCU's with add-on controls, which is more expensive than compliance with the standard for FCCU's without add-on controls. Therefore, the economic impacts of complying with the standard for FCCU's without add-on controls will be smaller.

The Agency believes that the monitoring costs associated with daily Method 8 testing are unlikely to affect SO_x reduction catalyst development. Even with the higher testing costs, SO_x reduction catalysts are still likely to be overall less costly to use than scrubbers. Thus, development on SO_x reduction catalysts will still continue as owners or operators try to minimize their costs in meeting these standards.

In conclusion, the Agency believes that the cost of daily Method 8 testing is reasonable in order to ensure daily compliance. Less expensive methods that allow the Agency to make equivalently accurate daily compliance determinations are encouraged and may be used subject to the approval of the Administrator.

Comment: One commenter stated that the proposed regulation does not supply sufficient information (calculation procedures) under Section 60.106, "Test Methods and Procedures," to determine total SO_x emissions.

Response: The EPA agrees with the commenter. Therefore, the regulation has been revised to indicate that modification to the calculation procedures specified in Reference Method 8 will be required to calculate total SO_x emissions as SO_2.

Comment: Many commenters suggested alternatives to daily Method 8 testing for demonstrating continuous compliance. The commenters suggested three basic types of alternatives: (1) The use of less frequent Method 8 testing, (2) periodic testing for SO_x until an SO_3 CEMS is developed, and (3) the use of continuous SO_2 monitors with periodic testing for SO_3. One commenter stated, in general, that the daily application of Method 8 is cumbersome, and thus, the proposed rule should contain provisions to allow the permittee to demonstrate continuous compliance based on a broader spectrum of options.

Response: The Agency has considered the alternatives suggested by the commenters. The Agency agrees that any test should not be performed more frequently than necessary and that a history of test data may show that daily testing is unnecessary. However, such a "history of test data" does not exist at this time and without such data, the Agency does not believe any of the alternative monitoring or testing schemes suggested can be implemented at this time and ensure that accurate continuous compliance determinations are made. Further, the commenters provided very little data to support their arguments, and available data show that the SO_3/SO_x ratio can be variable.

One of the commenters provided literature on an SO_3 monitor that they thought should be able to monitor SO_3 also. The information and literature provided were insufficient for the Agency to evaluate this potential for this particular monitor.

The Agency has examined other monitors for their ability to monitor SO_x. To date, none of the monitors examined has proven suitable. Therefore, the Agency could not require at this time such a monitor. The Agency does agree that many of these alternatives may be shown acceptable as more data on SO_x reduction catalyst use and SO_x emissions are generated. Therefore, the standard explicitly states that such alternatives supported by sufficient data may be approved on a case-by-case basis. Some of the criteria that may be considered are the SO_3/SO_x ratio, product feed variability, frequency of product slate changes, operational variability in regenerator conditions (e.g., excess oxygen, temperature), catalyst addition schedules, and FCCU operating conditions. The development of a successful SO_x monitor would also be an acceptable alternative, upon approval by the Administrator, to Method 8 testing. In the meantime, however, the Agency has retained daily Method 8 testing for determining compliance on a continuous basis for the standard for FCCU's without add-on controls.

Comment: Two commenters expressed concern over the possible interfering effects of particulates when performing Method 8 or revised Method 8.

Response: The EPA agrees that the presence of "other particulate matter" could invalidate the Method 8 test results. Therefore, appropriate changes have been made in the regulation to permit the insertion of a heated filter and probe in the sampling train, prior to the impingers. The heated probe and filter will prevent the particulate matter from getting into the impinger solution. Filters would be required that are at least 99.95 percent efficient, as required in Section 3.1.1 of Method 5. There is no indication or reason to suspect these filters would not eliminate the analysis problem. If analytical interference because of particulate matter still exists, then alternative analytical techniques (for example, ion chromatography) are available for use upon approval by the Administrator.

The Agency has not conducted testing of Method 8 as modified under these standards to specifically address the commenter's concerns. The Agency knows of no technical reason, however, as to why the modifications to Method 8 under this subpart would adversely affect the repeatability, reproducibility, precision, or accuracy of Method 8. In addition, EPA is currently developing test procedures for minimizing the sulfate interference in particulate matter measurements. The alternative of measuring both particulate matter and SO_x with the same equipment and analytical techniques will be addressed at that time.

The EPA acknowledges that ammonia has known interfering effects on SO_x determinations. We believe there are alternative techniques to eliminate the interference and are currently studying potential interference problems with respect to ammonia. Thus, in cases where ammonia and/or amines are expected or are known to create problems, the owner or operator should consult the Administrator for approval of alternative test methods.

Comment: One commenter stated that the collection of a grab sample using Reference Method 8 is less reliable than a continuous on-line analyzer, even though there could be some minor variation in the SO_3 to SO_2 ratio in the stack gas. The commenter believed the use of Method 8 could give unrealistic results where an unscrupulous operator could adjust the operating conditions prior to obtaining the daily sample.

Response: The revised proposed standards specified that the measurement of SO_x emissions from FCCU's using SO_x reduction catalysts would be accomplished by conducting revised Method 8 for one shift each day. The Agency knows of no evidence that the variation in total SO_x through the course of a day is any greater than the variation in the SO_2 to SO_3 ratio in the stack gas and, thus, knows of no evidence for the commenter's remarks.

The EPA assumes that operators will obtain valid samples that are representative of operating conditions at the facility and, therefore, will not alter operating conditions prior to sampling. Such deliberate actions on the part of an owner or operator to obtain unrealistic results clearly constitute circumvention of the standard and are illegal under subpart A, the General Provisions (40 CFR 60.12). Inspection of plant operating data by EPA and State personnel would lead to detection of such alteration of plant operation.

Comment: One commenter questioned whether 160 °C (320 °F) is the appropriate temperature for the heated probe and filter in the revised Method 8. This commenter also asked how the 160 °C (320 °F) temperature at the probe is reached if the stack temperature is hotter, or if it is colder. This commenter stated that if a "probe catch" is a deposit in the probe, the probe would soon plug up.

Response: The EPA based the selection of the temperature for the heated filter and probe in the revised Method 8 on the temperature specified in the proposed Method 5B and 5F (50 FR 21863, May 29, 1985), which are the methods for sampling particulate matter at FCCU's. The dew point for SO_3 may be higher than the temperature of the heated filter and probe (160 °C). In such instances, the filter would pick up condensed SO_3 (most likely, though, as sulfuric acid mist), thereby leading to a low estimate of SO_3 as measured in the impingers. The Agency believes that this problem is small because the filter would pick up only a small part of the sulfuric acid mist, and the rest would pass through the filter and be collected in the impingers. Thus, the Agency recognizes that, in such situations, a potential bias exists to underestimate emissions, but believes that it is small provided a temperature of 160 °C is maintained.

The materials used (glass and stainless steel) in the probes and filter holders are not subject to corrosion from sulfuric acid. Further, the probes and filter holder are removed each day (after the 3-hour test) for cleaning. In addition, FCCU operators would be required to conduct periodic leak checks. If leaks are detected in the system, or if the sampling system fails, then the system would need to be repaired.

With regard to the stack temperature being different from the probe temperature, if the stack temperature is hotter, there is no problem from an SO_x enforcement standpoint—more SO_x will be trapped in the impingers—and, thus, no temperature adjustment has to be made at the probe. However, if the stack temperature is colder, less SO_x will pass through the filter and a temperature adjustment has to be made. It is common practice to electrically heat the probe to attain the desired temperature.

Finally, with regard to plugging of the probe, as part of normal operating procedures, sampling conducted using revised Method 8 requires that the probe be cleaned out after each run and that the collected sample be discarded from the analysis. This procedure eliminates the potential problem brought up by the commenter.

Comment: One commenter asked why the isopropanol (IPA) impinger was deleted from Method 8.

Response: Method 8 was designed primarily for the separate capture and measurement of sulfuric acid and SO_2. The IPA impinger is used to collect sulfuric acid and SO_3, while the hydrogen peroxide impinger is used to collect SO_2. In the absence of the IPA impinger, the hydrogen peroxide impinger will collect all the SO_x compounds together. The current standards for SO_x reduction catalysts are based on total SO_x; there is no need to separate SO_2 from other sulfur emissions. Therefore, EPA eliminated the IPA impinger from Method 8, the effect of which is to simplify the test procedure, analysis, and calculations.

Feed Sulphur Cutoff

Comment: One commenter felt that the cost of testing the feed sulfur at FCCU's using the alternative feed sulfur cutoff is too expensive to be performed more often than is necessary and suggested that such testing should be required once per week if the feed is previously found to contain below 0.3 percent sulfur in every sample for a week.

Response: For these standards, owners and operators are required to determine compliance on a continuous basis (i.e., on a daily basis). As described in the proposed standards, most refiners manually sample the FCCU fresh feed once per day. Fresh feed sulfur content, however, may change on an hourly basis. Requiring samples to be collected once per hour is not practical using manual sampling techniques. Therefore, the Agency selected a sampling frequency of one sample per 8-hour shift. This frequency would measure major fluctuations in fresh feed sulfur level and is reasonable considering current refinery sampling practices. The sampling program suggested by the commenter would not allow the Agency to be sure that the owner or operator is in fact meeting the standard on a daily basis. Furthermore, past feed usage is not a good indicator of future use; many refiners use different feeds or feed blends for short periods of time. Therefore, the Agency has retained daily testing for feed sulfur content for those operators using this alternative standard.

Compliance

Source Operation During Malfunctions

Comment: One commenter requested that EPA consider establishing standards that allow a certain amount of scrubber downtime without requiring an FCCU shutdown.

Response: The General Provisions in 40 CFR part 60 provide for malfunction of control equipment. "Malfunction" means only sudden and unavoidable failure of air pollution control equipment, process equipment, or of a process to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition, are not considered malfunctions. As stated in § 60.8(c), emissions in excess of a standard due to a malfunction do not represent a violation of the standard. In addition, scrubbers currently applied to FCCU's have demonstrated reliability levels in excess of 95 percent. Thus, it is unnecessary to provide a provision in the standards for scrubber downtime.

Comment: One commenter asked if the affected facility is allowed to continue operating during continuous emission monitor malfunctions.

Response: An affected facility may continue to operate during continuous emission monitor malfunctions. However, as prescribed under 40 CFR 60.7(b) and (c)(3) of the General Provisions, the owner or operator shall maintain records of any periods during which a continuous monitoring system or monitoring device is inoperative, and the quarterly (or semiannual, if no exceedances have occurred during a particular quarter) compliance report shall include the date and time identifying each period during which the continuous monitoring system was inoperative, except for zero and span checks, and the nature of the system repairs or adjustments. It should be noted that failure to properly operate or maintain a continuous monitoring system would be considered as a violation rather than a malfunction (see 40 CFR 60.105 and 60.13).

Changing Compliance Method

Comment: Four commenters wrote that the 90-day notification prior to changing from one method of compliance to another should be modified to allow for an immediate change in emergency cases. Two of these commenters stated that no prior notification should be required provided that records appropriate to demonstrate compliance are maintained, and EPA is notified in writing of the change in compliance method.

Response: The regulation now requires that daily compliance determinations be made for all of the standards. Thus, EPA agrees with the commenters and has removed the requirements for prior notification provided that records appropriate to demonstrate compliance with the regulation are maintained. Additionally, a quarterly report with notification of the change must be submitted to the Administrator in the quarter following such a change even if no violations of a standard have occurred.

Modification/Reconstruction

Comment: One commenter stated that routine maintenance items should not be included in determining if a facility is modified or reconstructed because many of these items are frequently repaired without a resultant emissions increase. Another commenter stated that the affected facility should be redefined to include the fractionator and gas plant because rebuilding work in a single turnaround of an affected facility can commonly exceed 50 percent of the cost of a new unit. Also, the cost of rebuilding work on an affected facility can represent 20 percent of the new unit cost of an entire FCCU. To a refiner, an entire FCCU includes the fractionator and gas plant. These two units usually do not require any significant rebuilding.

Response: The reconstruction provision (40 CFR 60.15) cannot be invoked until 50 percent of the "fixed capital cost" to replace the existing facility with a comparable, new facility has been incurred by the owner or operator. The period in which the FCCU is shut down for maintenance and repair is called a turnaround. During a typical turnaround, regenerator refractory linings, cyclones, and other internal components are inspected and repaired or replaced as required. Based on information from the refining industry, regenerator components have a useful life ranging from 10 years to an indefinite period of time when they are repaired and maintained during turnarounds. The costs used in the summation to determine the total fixed capital cost incurred are those costs incurred to replace components. The costs incurred during maintenance and repair of the existing facility's components (assuming components are not replaced) are not included in the summation of expended fixed capital costs. Thus, there is no need to specifically exempt routine maintenance items from the reconstruction provisions.

The EPA disagrees with the comment that rebuilding work typically can exceed 50 percent of the capital cost of a new affected facility. The EPA examined data from section 114 letter responses, trip reports, literature articles, and companies who provide turnaround services to refineries. These data led EPA to conclude that routine rebuilding is less than 50 percent of the cost of a new affected facility. As discussed above, this is because regenerator components are typically repaired rather than replaced during a turnaround. If several major changes, such as increasing the FCCU capacity, changing to a heavier or more sour crude oil, or converting to HTR, occur during a single turnaround, the cost may approach or surpass the 50 percent point. Such major changes are not, however, a typical turnaround occurrence. The possibility that rebuilding work may exceed 50 percent of the cost of a new unit is an inadequate reason to broaden the definition of the affected facility (i.e., restrict invoking the reconstruction provision).

The modification provision (40 CFR 60.14) is invoked when any physical or operational change to an existing facility results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies. As the actions described by the commenter do not increase emissions, the modification provision would not be invoked. In addition, paragraph (f) of § 60.14 specifies that routine maintenance, repair, and replacement by themselves, shall not be considered modifications.

Comment: One commenter stated that a 1-calendar year or a 12-month "inclusion period" for reconstruction is more logical than a 2-year period. A refiner with a normal 2-year turnaround could be affected by the reconstruction provisions of the standards if a shutdown began 1 or 2 months prematurely. A refiner would not install a sizeable process modification during a routine shutdown period due to the excessive downtime incurred.

Response: The EPA considered again the 2-year period and concluded that a 1-calendar year or a 12-month "inclusion period" for reconstruction is not more logical than a 2-year period for FCCU's. Information from industry and literature (see proposal BID, p. 5–3) indicates that the normal turnaround schedule for revamping FCCU regenerators is every 3 years (i.e., a maximum of one turnaround would occur during each 2-year period of operation). A process unit turnaround typically includes maintenance and repair items that do not qualify as fixed capital costs and therefore, a turnaround is not likely to be a "reconstruction." The Agency also does not expect that the 2-year period will alter decisions by an FCCU's owner or operator on when to replace equipment; that is, the FCCU owner or operator is not likely to prolong the useful life of the regenerator components with the intent of avoiding the NSPS. Therefore, for this particular NSPS, EPA believes that the 2-year period provides a reasonable, objective method of determining whether an owner or operator of an FCCU regenerator is actually "proposing" extensive component replacement, within the original intent of § 60.15.

Recordkeeping and Reporting

Comment: The OMB commented that quarterly reporting was too frequent, and that semiannual reporting would allow the Agency to obtain the necessary information.

Response: For FCCU's, EPA has concluded that quarterly reporting (or semiannual reporting if no exceedances have occurred during a particular quarter) is the appropriate reporting frequency for the following reasons. The major reason is that the reports contain direct compliance information rather than indicators of the source's performance. Therefore, enforcement action can be taken quickly because no further testing is necessary for documentation. The FCCU is one of several significant emission sources in petroleum refineries, so periods of excess emissions could have a significant impact on the environment. This is particularly true because refineries generally are located in clusters near industrial, urban, populated, nonattainment areas. Because the refinery generally does not save money by operating the control techniques correctly and the pollutants cannot be recovered for resale, there is little incentive for this source category to be self-regulated. Therefore, to ensure that sources are not out of compliance for long periods of time during which significant environmental impacts could occur, quarterly reporting is appropriate for quarters when facilities have had a period when the standard has been exceeded. In addition, the amount of data to be provided in these cases is reasonable. Sources complying with the proposed revised standard would need to supply only a semiannual negative declaration statement. Only noncompliant sources would be required to provide additional information in the quarterly compliance reports.

VIII. Administrative

The docket is an organized and complete file of all the information considered by EPA in the development of this rulemaking. The docket is a dynamic file, since material is added throughout the rulemaking process. The docketing system is intended to allow members of the public and industries involved to readily identify and locate documents so that they can effectively participate in the rulemaking process. Along with the statement of basis and purpose of the proposed and promulgated standards and EPA responses to significant comments, the contents of the docket, except for interagency review materials, will serve as the record in case of judicial review (section 307(d)(7)(A)).

The effective date of this regulation is August 17, 1989. Section 111 of the Clean Air Act provides that standards of performance or revisions thereof become effective upon promulgation and apply to affected facilities of which the construction or modification was commenced after the date of proposal (January 17, 1984).

As prescribed by section 111, the promulgation of these standards was preceded by the Administrator's determination that petroleum refineries contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. In accordance with section 117 of the Act, publication of these promulgated standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

This regulation will be reviewed 4 years from the date of promulgation as required by the Clean Air Act. This review will include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements.

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under section 111(b) of the Act. An economic impact assessment was prepared for this regulation and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the standards to ensure that cost was carefully considered in determining BDT. The economic impact assessment is included in the BID for the proposed standards and the promulgated standards.

During the first 3 years that the proposed standards would be in effect, the public reporting burden for collection of information, including time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information is estimated to be 4,360 averaged annual hours. The estimated burden for a typical respondent (including initial reports) ranges from about 660 hours per year for complying with the feed sulfur standard to about 980 hours per year for complying with the standard for add-on controls. The resources required by EPA and State and local agencies to process the reports and to maintain records for the first 3 years would be about 0.15 person-years per year.

Information collection requirements associated with this regulation have been approved by OMB under the provisions of the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* and have been assigned OMB control number 2060–0061.

Under Executive Order 12291, EPA is required to judge whether a regulation is a "major rule" and therefore subject to the requirements of a regulatory impact analysis (RIA). The Agency has determined that this regulation would result in none of the adverse economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule." The fifth-year annualized costs of the standards are expected to be $45.8 million for the projected 17 newly constructed, modified, and reconstructed FCCU regenerators that could be affected by the standards during the first 5 years after the effective date of the standards. The economic analysis shows that the standards would not have a significant impact on petroleum refineries if all FCCU owners or operators subject to these standards used scrubbers. The standards would have a small effect on profitability (a profit decrease of 0.8 percent). The Agency has, therefore, concluded that this regulation is not a "major rule" under Executive Order 12291.

The Regulatory Flexibility Act of 1980 requires the identification of potentially adverse impacts of Federal regulations upon small business entities. The Act specifically requires the completion of a Regulatory Flexibility Analysis in those instances where small business impacts are possible. Because these standards impose no adverse economic impacts, a Regulatory Flexibility Analysis has not been conducted.

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

List of Subjects in 40 CFR Part 60

Air pollution control, Incorporation by reference, Intergovernmental relations, Petroleum refineries, Reporting and recordkeeping requirements.

Dated: July 27, 1989.

William K. Reilly,
Administrator.

40 CFR part 60 is amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

1. The authority citation for part 60 continues to read as follows:

Authority: 42 U.S.C. 7401, 7411, 7414, 7416, 7601.

2. The table of contents for subpart J is revised to read as follows:

Subpart J—Standards of Performance for Petroleum Refineries

Sec.
60.100 Applicability, designation of affected facility, and reconstruction.
60.101 Definitions.
60.102 Standard for particulate matter.
60.103 Standard for carbon monoxide.
60.104 Standards for sulfur oxides.
60.105 Monitoring of emissions and operations.
60.106 Test methods and procedures.
60.107 Reporting and recordkeeping requirements.
60.108 Performance test and compliance provisions.
60.109 Delegation of authority.

3. Section 60.17 of subpart A—General Provisions is amended by adding paragraphs (a) (56), (57), (58), and (59) to read as follows:

§ 60.17 Incorporations by reference.

* * * * *

(a) * * *

(56) ASTM D129–64 (Reapproved 1978), Standard Test Method for Sulfur in Petroleum Products (General Bomb Method), IBR approved August 17, 1989, for § 60.106(h)(2).

(57) ASTM D1552–83, Standard Test Method for Sulfur in Petroleum Products (High-Temperature Method), IBR approved August 17, 1989, for § 60.106(h)(2).

(58) ASTM D2622–87, Standard Test Method for Sulfur in Petroleum Products by X-Ray Spectrometry, IBR approved August 17, 1989, for § 60.106(h)(2).

(59) ASTM D1266–87, Standard Test Method for Sulfur in Petroleum Products (Lamp Method), IBR approved August 17, 1989, for § 60.106(h)(2).

* * * * *

4. Subpart J, § 60.100 is amended by revising the section heading and paragraph (b) and by adding paragraphs (c), (d), and (e) to read as follows:

§ 60.100 Applicability, designation of affected facility, and reconstruction.

* * * * *

(b) Any fluid catalytic cracking unit catalyst regenerator or fuel gas combustion device under paragraph (a) of this section which commences construction or modification after June 11, 1973, or any Claus sulfur recovery plant under paragraph (a) of this section which commences construction or modification after October 4, 1976, is subject to the requirements of this subpart except as provided under paragraphs (c) and (d) of this section.

(c) Any fluid catalytic cracking unit catalyst regenerator under paragraph (b) of this section which commences construction or modification on or before January 17, 1984, is exempted from § 60.104(b).

(d) Any fluid catalytic cracking unit in which a contact material reacts with petroleum derivatives to improve feedstock quality and in which the contact material is regenerated by burning off coke and/or other deposits and that commences construction or modification on or before January 17, 1984, is exempt from this subpart.

(e) For purposes of this subpart, under § 60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components which are or will be replaced pursuant to all continuous programs of component replacement which are commenced within any 2-year period following January 17, 1984. For purposes of this paragraph, "commenced" means that an owner or operator has undertaken a continuous program of component replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of component replacement.

5. Section 60.101 is amended by adding paragraphs (m), (n), (o), (p), and (q) to read as follows:

§ 60.101 Definitions.

* * * * *

(m) *Fluid catalytic cracking unit* means a refinery process unit in which petroleum derivatives are continuously charged; hydrocarbon molecules in the presence of a catalyst suspended in a fluidized bed are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing; and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

(n) *Fluid catalytic cracking unit catalyst regenerator* means one or more regenerators (multiple regenerators) which comprise that portion of the fluid catalytic cracking unit in which coke burn-off and catalyst or contact material regeneration occurs, and includes the regenerator combustion air blower(s).

(o) *Fresh feed* means any petroleum derivative feedstock stream charged directly into the riser or reactor of a fluid catalytic cracking unit except for petroleum derivatives recycled within the fluid catalytic cracking unit, fractionator, or gas recovery unit.

(p) *Contact material* means any substance formulated to remove metals, sulfur, nitrogen, or any other contaminant from petroleum derivatives.

(q) *Valid day* means a 24-hour period in which at least 18 valid hours of data are obtained. A "valid hour" is one in which at least 2 valid data points are obtained.

6. Section 60.102 is amended by adding introductory text to the section and revising the introductory text of paragraph (a) to read as follows:

§ 60.102 Standard for particulate matter.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator:

* * * * *

7. Section 60.103 is revised to read as follows:

§ 60.103 Standard for carbon monoxide.

Each owner or operator of any fluid catalytic cracking unit catalyst regenerator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the fluid catalytic cracking unit catalyst regenerator will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall discharge or cause the discharge into the atmosphere from any fluid catalytic cracking unit catalyst regenerator any gases which contain carbon monoxide in excess of 0.050 percent by volume.

8. Section 60.104 is amended by revising the section heading, adding introductory text to the section, revising the introductory text of paragraph (a), and adding paragraphs (b), (c), and (d) to read as follows:

§ 60.104 Standards for sulfur oxides.

Each owner or operator that is subject to the requirements of this subpart shall comply with the emission limitations set forth in this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

(a) No owner or operator subject to the provisions of this subpart shall:

* * * * *

(b) Each owner or operator that is subject to the provisions of this subpart shall comply with one of the following conditions for each affected fluid catalytic cracking unit catalyst regenerator:

(1) With an add-on control device, reduce sulfur dioxide emissions to the atmosphere by 90 percent or maintain sulfur dioxide emissions to the atmosphere less than or equal to 50 ppm by volume (vppm), whichever is less stringent; or

(2) Without the use of an add-on control device, maintain sulfur oxides emissions calculated as sulfur dioxide to the atmosphere less than or equal to 9.8 kg/1,000 kg coke burn-off; or

(3) Process in the fluid catalytic cracking unit fresh feed that has a total sulfur content no greater than 0.30 percent by weight.

(c) Compliance with paragraph (b)(1), (b)(2), or (b)(3) of this section is determined daily on a 7-day rolling average basis using the appropriate procedures outlined in § 60.106.

(d) A minimum of 22 valid days of data shall be obtained every 30 rolling successive calendar days when complying with paragraph (b)(1) of this section.

9. Section 60.105 is amended by revising the section heading, revising the introductory text of paragraph (a); adding and reserving paragraph (a)(7), and adding paragraphs (a)(8), (a)(9), (a)(10), (a)(11), (a)(12), (a)(13), and (a)(14); revising paragraph (c); and removing paragraph (e)(4) to read as follows:

§ 60.105 Monitoring of emissions and operations.

(a) Continuous monitoring systems shall be installed, calibrated, maintained, and operated by the owner or operator subject to the provisions of this subpart as follows:

* * * * *

(7) [Reserved]

(8) An instrument for continuously monitoring and recording concentrations of sulfur dioxide in the gases at both the inlet and outlet of the sulfur dioxide control device from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(1). The span value of the inlet monitor shall be set at 125 percent of the maximum estimated hourly potential sulfur dioxide emission concentration entering the control device, and the span value of the outlet monitor shall be set at 50 percent of the maximum estimated hourly potential sulfur dioxide emission concentration entering the control device.

(9) An instrument for continuously monitoring and recording concentrations of sulfur dioxide in the gases discharged into the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply specifically with the 50 vppm emission limit under § 60.104(b)(1). The span value of the monitor shall be set at 50 percent of the maximum hourly potential sulfur dioxide emission concentration entering the control device.

(10) An instrument for continuously monitoring and recording concentrations of oxygen (O_2) in the gases at both the inlet and outlet of the sulfur dioxide control device (or the outlet only if specifically complying with the 50 vppm standard) from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator has elected to comply with § 60.104(b)(1). The span of this continuous monitoring system shall be set at 10 percent.

(11) The continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(12) The owner or operator shall follow appendix F, Procedure 1, including quarterly accuracy determinations and daily calibration drift tests, for the continuous monitoring systems under paragraphs (a)(8), (a)(9), and (a)(10) of this section.

(13) When seeking to comply with § 60.104(b)(1), when emission data are not obtained because of continuous monitoring system breakdowns, repairs, calibration checks and zero and span adjustments, emission data will be obtained by using one of the following methods to provide emission data for a minimum of 18 hours per day in at least 22 out of 30 rolling successive calendar days.

(i) The reference methods as described in paragraph (a)(14) of this section;

(ii) A spare continuous monitoring system; or

(iii) Other monitoring systems as approved by the Administrator.

(14) Reference methods used to supplement continuous monitoring system data to meet the minimum data requirements in paragraph § 60.104(d) will be used as described below or as otherwise approved by the Administrator.

(i) Reference Methods 6, 6B, or 8 are used. The sampling location(s) are the same as those specified for the continuous emission monitoring system.

(ii) For Method 6, the minimum sampling time is 20 minutes and the minimum sampling volume is 0.02 dscm (0.71 dscf) for each sample. Samples are taken at approximately 60-minute intervals. Each sample represents a 1-hour average. A minimum of 18 valid samples is required to obtain one valid day of data.

(iii) For Method 6B, collection of a sample representing a minimum of 18 hours is required to obtain one valid day of data.

(iv) For Method 8, the procedures as outlined in § 60.106. The equivalent of 18 hours of sampling is required to obtain one valid day of data.

* * * * *

(c) The average coke burn-off rate (thousands of kilograms per hour) and hours of operation shall be recorded daily for any fluid catalytic cracking unit catalyst regenerator subject to § 60.102, § 60.103, or § 60.104(b)(2).

* * * * *

10. Section 60.106 is amended by revising the units in the definition of R_c in paragraph (a)(7) and adding paragraphs (e), (f), (g), and (h) to read as follows:

§ 60.106 Test methods and procedures.

(a) * * *

(7) * * *

R_c = coke burn-off rate, kg/hr (English units: 1000 lb/hr).

* * * * *

(e) Each performance test conducted for the purpose of determining compliance under § 60.104(b) shall consist of all testing performed over a 7-day period using the applicable test methods and procedures specified in this section. To determine compliance, the arithmetic mean of the results of all the tests shall be compared with the applicable standard.

(f) For the purpose of determining compliance with § 60.104(b)(1), the following calculation procedures shall be used:

(1) Calculate each 1-hour average concentration (dry, zero percent oxygen, vppm) of sulfur dioxide at both the inlet and the outlet to the add-on control device as specified in § 60.13(h). These calculations are made using the emission data collected under § 60.105(a).

(2) Calculate a 7-day average (arithmetic mean) concentration of sulfur dioxide for the inlet and for the outlet to the add-on control device using all of the 1-hour average concentration values obtained during seven successive 24-hour periods.

(3) Calculate the 7-day average percent reduction using the following equation:

$$R_{SO_2} = 100(C_{SO_2(i)} - C_{SO_2(o)})/C_{SO_2(i)}$$

where:

R_{SO_2} = 7-day average sulfur dioxide emission reduction, percent

$C_{SO_2(i)}$ = sulfur dioxide emission concentration determined in § 60.106(f)(2) at the inlet to the add-on control device, vppm

$C_{SO_2(o)}$ = sulfur dioxide emission concentration determined in § 60.106(f)(2) at the outlet to the add-on control device, vppm

100 = conversion factor, decimal to percent

(4) Outlet concentrations of sulfur dioxide from the add-on control device for compliance with the 50 vppm standard, reported on a dry, O_2-free basis, shall be calculated using the procedures outlined in § 60.106(f) (1) and (2) above, but for the outlet monitor only.

(5) If supplemental sampling data are used for determining the 7-day averages under paragraph (f) of this section and such data are not hourly averages, then the value obtained for each supplemental sample shall be assumed to represent the hourly average for each hour over which the sample was obtained.

(6) For the purpose of adjusting pollutant concentrations to zero percent oxygen, the following equation shall be used:

$$C_{adj} = C_{meas}\,[20.9_c/(20.9 - \%O_2)]$$

where:

C_{adj} = pollutant concentration adjusted to zero percent oxygen, ppm or g/dscm

C_{meas} = pollutant concentration measured on a dry basis, ppm or g/dscm

20.9_c = 20.9 percent oxygen−0.0 percent oxygen (defined oxygen correction basis), percent

20.9 = oxygen concentration in air, percent

$\%O_2$ = oxygen concentration measured on a dry basis, percent

(g) For the purpose of determining compliance with § 60.104(b)(2), the following reference methods and calculation procedures shall be used except as provided in paragraph (g)(12) of this section:

(1) One 3-hour test shall be performed each day.

(2) For gases released to the atmosphere from the fluid catalytic cracking unit catalyst regenerator:

(i) Method 8 as modified in § 60.106(g)(3) for the concentration of sulfur oxides calculated as sulfur dioxide and moisture content,

(ii) Method 1 for sample and velocity traverses,

(iii) Method 2 calculation procedures (data obtained from Methods 3 and 8) for velocity and volumetric flow rate, and

(iv) Method 3 for gas analysis.

(3) Method 8 shall be modified by the insertion of a heated glass fiber filter between the probe and first impinger. The probe liner and glass fiber filter temperature shall be maintained above 160°C (320°F). The isopropanol impinger shall be eliminated. Sample recovery procedures described in Method 8 for container No. 1 shall be eliminated. The heated glass fiber filter also shall be excluded; however, rinsing of all connecting glassware after the heated glass fiber filter shall be retained and included in container No. 2. Sampled volume shall be at least 1 dscm.

(4) For Method 3, the integrated sampling technique shall be used.

(5) Sampling time for each run shall be at least 3 hours.

(6) All testing shall be performed at the same location. Where the gases discharged by the fluid catalytic cracking unit catalyst regenerator pass through an incinerator-waste heat boiler in which auxiliary or supplemental gaseous, liquid, or solid fossil fuel is burned, testing shall be conducted at a point between the regenerator outlet and the incinerator-waste heat boiler. An alternative sampling location after the waste heat boiler may be used if alternative coke burn-off rate equations, and, if requested, auxiliary/supplemental fuel SO_x credits, have been submitted to and approved by the Administrator prior to sampling.

(7) Coke burn-off rate shall be determined using the procedures specified under paragraph (a)(4) of this section, unless paragraph (g)(6) of this section applies.

(8) Calculate the concentration of sulfur oxides as sulfur dioxide using equation 8–3 in Section 6.5 of Method 8 to calculate and report the total concentration of sulfur oxides as sulfur dioxide (C_{SO_x}).

(9) Sulfur oxides emission rate calculated as sulfur dioxide shall be determined for each test run by the following equation:

$$E_{SO_x} = C_{SO_x} Q_{sd}/1{,}000$$

where:

E_{SO_x} = sulfur oxides emission rate calculated as sulfur dioxide, kg/hr

C_{SO_x} = sulfur oxides emission concentration calculated as sulfur dioxide, g/dscm

Q_{sd} = dry volumetric stack gas flow rate corrected to standard conditions, dscm/hr

1,000 = conversion factor, g to kg

(10) Sulfur oxides emissions calculated as sulfur dioxide per 1,000 kg coke burn-off in the fluid catalytic cracking unit catalyst regenerator shall be determined for each test run by the following equation:

$$R_{SO_x} = (E_{SO_x}/R_c)$$

where:

R_{SO_x} = sulfur oxides emissions calculated as sulfur dioxide, kg/1,000 kg coke burn-off

E_{SO_x} = sulfur oxides emission rate calculated as sulfur dioxide, kg/hr

R_c = coke burn-off rate, 1,000 kg/hr

(11) Calculate the 7-day average sulfur oxides emission rate as sulfur dioxide per 1,000 kg of coke burn-off by dividing the sum of the individual daily rates by the number of daily rates summed.

(12) An owner or operator may, upon approval by the Administrator, use an alternative method for determining compliance with § 60.104(b)(2), as provided in § 60.8(b). Any requests for approval must include data to demonstrate to the Administrator that the alternative method would produce results adequate for the determination of compliance.

(h) For the purpose of determining compliance with § 60.104(b)(3), the following analytical methods and calculation procedures shall be used:

(1) One fresh feed sample shall be collected once per 8-hour period.

(2) Fresh feed samples shall be analyzed separately by using any one of the following applicable analytical test methods: ASTM D129–64 (Reapproved 1978), ASTM D1552–83, ASTM D2622–87, or ASTM D1266–87. (These methods are incorporated by reference: see § 60.17.) The applicable range of some of these ASTM methods is not adequate to measure the levels of sulfur in some fresh feed samples. Dilution of samples prior to analysis with verification of the dilution ratio is acceptable upon prior approval of the Administrator.

(3) If a fresh feed sample cannot be collected at a single location, then the fresh feed sulfur content shall be determined as follows:

(i) Individual samples shall be collected once per 8-hour period for each separate fresh feed stream charged directly into the riser or reactor of the fluid catalytic cracking unit. For each sample location the fresh feed volumetric flow rate at the time of collecting the fresh feed sample shall be measured and recorded. The same method for measuring volumetric flow rate shall be used at all locations.

(ii) Each fresh feed sample shall be analyzed separately using the methods specified under paragraph (h)(2) of this section.

(iii) Fresh feed sulfur content shall be calculated for each 8-hour period using the following equation:

$$S_f = \sum_{i=1}^{n} \frac{S_i Q_i}{Q_f}$$

where:

S_f = fresh feed sulfur content expressed in percent by weight of fresh feed.

n = number of separate fresh feed streams charged directly to the riser or reactor of the fluid catalytic cracking unit.

Q_f = total volumetric flow rate of fresh feed charged to the fluid catalytic cracking unit.

S_i = fresh feed sulfur content expressed in percent by weight of fresh feed for the "ith" sampling location.

Q_i = volumetric flow rate of fresh feed stream for the "ith" sampling location.

(4) Calculate a 7-day average (arithmetic mean) sulfur content of the fresh feed using all of the fresh feed sulfur content values obtained during seven successive 24-hour periods.

11. Section 60.107 is added to subpart J to read as follows:

§ 60.107 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to § 60.104(b) shall notify the Administrator of the specific provisions of § 60.104(b) with which the owner or operator seeks to comply. Notification shall be submitted with the notification of initial startup required by § 60.7(a)(3). If an owner or operator elects at a later date to comply with an alternative provision of § 60.104(b), then the Administrator shall be notified by the owner or operator in the quarterly (or semiannual) report described in paragraphs (c) and (d) of this section for the quarter during which the change occurred.

(b) Each owner or operator subject to § 60.104(b) shall record and maintain the following information:

(1) If subject to § 60.104(b)(1),

(i) All data and calibrations from continuous monitoring systems located at the inlet and outlet to the control device, including the results of the daily drift tests and quarterly accuracy assessments required under appendix F, Procedure 1;

(ii) Measurements obtained by supplemental sampling (refer to § 60.105(a)(13) and (a)(14)) for meeting minimum data requirements; and

(iii) The written procedures for the quality control program required by appendix F, Procedure 1.

(2) If subject to § 60.104(b)(2), measurements obtained in the daily Method 8 testing, or those obtained by alternative measurement methods, if § 60.106(g)(12) applies.

(3) If subject to § 60.104(b)(3), data obtained from the daily feed sulfur tests.

(4) Each 7-day rolling average compliance determination.

(c) Each owner or operator subject to § 60.104(b) shall submit a report each quarter except as provided by paragraph (d) of this section. The following information shall be contained in each quarterly report:

(1) Any 7-day period during which:

(i) The average percent reduction and average concentration of sulfur dioxide on a dry, O_2-free basis in the gases discharged to the atmosphere from any fluid cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(1) is below 90 percent and above 50 vppm, as measured by the continuous monitoring system prescribed under § 60.105(a)(8), or above 50 vppm, as measured by the outlet continuous monitoring system prescribed under § 60.105(a)(9). The average percent reduction and average sulfur dioxide concentration shall be determined using the procedures specified under § 60.106(f);

(ii) The average emission rate of sulfur dioxide in the gases discharged to the atmosphere from any fluid catalytic cracking unit catalyst regenerator for which the owner or operator seeks to comply with § 60.104(b)(2) exceeds 9.8 kg SO_x per 1,000 kg coke burn-off, as measured by the daily testing prescribed under § 60.106(g). The average emission rate shall be determined using the procedures specified under § 60.106(g); and

(iii) The average sulfur content of the fresh feed for which the owner or operator seeks to comply with § 60.104(b)(3) exceeds 0.30 percent by weight. The fresh feed sulfur content, a 7-day rolling average, shall be determined using the procedures specified under § 60.106(h).

(2) Any 30-day period in which the minimum data requirements specified in § 60.104(d) are not obtained.

(3) For each 7-day period during which an exceedance has occurred as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section:

(i) The date that the exceedance occurred;

(ii) An explanation of the exceedance;

(iii) Whether the exceedance was concurrent with a startup, shutdown, or malfunction of the fluid catalytic cracking unit or control system; and

(iv) A description of the corrective action taken, if any.

(4) If subject to § 60.104(b)(1),

(i) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the inlet continuous monitoring system;

(ii) The dates for which and brief explanations as to why fewer than 18 valid hours of data were obtained for the outlet continuous monitoring system;

(iii) Identification of times when hourly averages have been obtained based on manual sampling methods;

(iv) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system; and

(v) Description of any modifications to the continuous monitoring system that could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(vi) Results of daily drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1.

(5) If subject to § 60.104(b)(2), for each day in which a Method 8 sample result was not obtained, the date for which and brief explanation as to why a Method 8 sample result was not obtained, for approval by the Administrator.

(6) If subject to § 60.104(b)(3), for each 8-hour shift in which a feed sulfur measurement was not obtained, the date for which and brief explanation as to why a feed sulfur measurement was not obtained, for approval by the Administrator.

(d) If no exceedances (as defined in paragraphs (c)(1)(i) through (c)(1)(iii) and (c)(2) of this section) occur in a quarter, and if the owner or operator has not changed the standard under § 60.104(b) under which compliance is obtained, then the owner or operator may submit a semiannual report in which a statement is included that states that no exceedances had occurred during the affected quarter(s). If the owner or operator elects to comply with an alternative provision of § 60.104(b), a quarterly report must be submitted for the quarter during which a change occurred.

(e) For any periods for which sulfur dioxide or oxides emissions data are not available, the owner or operator of the affected facility shall submit a signed statement indicating if any changes were made in operation of the emission control system during the period of data unavailability which could affect the ability of the system to meet the applicable emission limit. Operations of the control system and affected facility during periods of data unavailability are to be compared with operation of the control system and affected facility before and following the period of data unavailability.

(f) The owner or operator of the affected facility shall submit a signed statement certifying the accuracy and completeness of the information contained in the report.

(Approved by the Office of Management and Budget under control number 2060–0061)

12. Section 60.108 is added to subpart J to read as follows:

§ 60.108 Performance test and compliance provisions.

(a) Section 60.8(d) shall apply to the initial performance test specified under paragraph (c) of this section, but not to the daily performance tests required thereafter as specified in § 60.108(d). Section 60.8(f) does not apply when determining compliance with the standards specified under § 60.104(b). Performance tests conducted for the purpose of determining compliance under § 60.104(b) shall be conducted according to the applicable procedures specified under § 60.106.

(b) Owners or operators who seek to comply with § 60.104(b)(3) shall meet that standard at all times, including periods of startup, shutdown, and malfunctions.

(c) The initial performance test shall consist of the initial 7-day average calculated for compliance with § 60.104(b)(1), (b)(2), or (b)(3).

(d) After conducting the initial performance test prescribed under § 60.8, the owner or operator of a fluid catalytic cracking unit catalyst regenerator subject to § 60.104(b) shall conduct a performance test for each successive 24-hour period thereafter. The daily performance tests shall be conducted according to the appropriate procedures specified under § 60.106. In the event that a sample collected under § 60.106(g) or (h) is accidentally lost or conditions occur in which one of the samples must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operators' control, compliance may be determined using available data for the 7-day period.

(e) Each owner or operator subject to § 60.104(b) who has demonstrated compliance with one of the provisions of § 60.104(b) but at a later date seeks to comply with another of the provisions of § 60.104(b) shall begin conducting daily performance tests as specified under paragraph (d) of this section immediately upon electing to become subject to one of the other provisions of § 60.104(b). The owner or operator shall furnish the Administrator a written notification of the change in a quarterly report that must be submitted for the quarter in which the change occurred.

13. Section 60.109 is added to subpart J to read as follows:

§ 60.109 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under section 111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which shall not be delegated to States:

(1) Section 60.105(a)(13)(iii).

(2) Section 60.106(g)(12).

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