

changing the regulation. The regulation is adopted as final.

A technical correction to paragraph (c)(3) is being made by adding the phrase, "disabling effects of." This phrase was inadvertently omitted in the proposed regulation. No substantive changes are being made.

VA has determined that these amended regulations do not contain a major rule as that term is defined in Executive Order 12291, Federal Regulations. The proposal will not have a \$100 million annual effect on the economy, will not cause a major increase in costs or prices, and will not have any other significant adverse effects on the economy.

These regulatory amendments are retroactively effective. These are interpretive rules which implement statutory provisions. Moreover, VA finds that good cause exists for making these rules, like the section of the law which they implement, retroactively effective to the date of enactment. A delayed effective date would be contrary to statutory design; would complicate implementation of this provision of law; and might result in a denial of a benefit to a veteran who is entitled by law to that benefit.

The Secretary certifies that these amendments will not, if promulgated, have a significant economic impact on a substantial number of small entities as they are defined in the Regulatory Flexibility Act (RFA) 5 U.S.C. 601-612. Pursuant to 5 U.S.C. 605(b), these rules are therefore exempt from the initial and final flexibility analyses requirements of sections 603 and 604. The reason for this certification is that the amendments only affect the rights of individual beneficiaries. No new regulatory burdens are imposed on small entities by these amendments.

The Catalog of Federal Domestic Assistance number is 64 116.

List of Subjects in 38 CFR Part 21

Civil rights, Claims, Education, Grant programs, Loan programs, Reporting requirements, Schools, Veterans, Vocational education, Vocational rehabilitation.

Approved: August 30, 1990.

Edward J. Derwinski,
Secretary of Veterans Affairs.

PART 21—[AMENDED]

38 CFR part 21, Vocational Rehabilitation and Education, is amended by revising paragraph (c) of § 21.42 to read as follows:

§ 21.42 Basic period of eligibility deferred.

* * * * *

(c) *Medical condition prevents initiation or continuation.* (1) The basic 12-year period of eligibility shall not begin to run or continue to run during any period of 30 days or more in which the veteran's participation in vocational rehabilitation is infeasible because of the veteran's medical condition, which condition may include the disabling effects of chronic alcoholism, subject to paragraph (c)(5) of this section. The 12-year period shall begin or resume when it is feasible for the veteran to participate in a vocational rehabilitation program, as that term is defined in § 21.35.

(2) The term "disabling effects of chronic alcoholism" means alcohol-induced physical or mental disorders or both, such as habitual intoxication, withdrawal, delirium, amnesia, dementia, and other like manifestations of chronic alcoholism which, in the particular case:

(i) Have been medically diagnosed as manifestations of alcohol dependency or chronic alcohol abuse; and

(ii) Are determined to have prevented commencement or completion of the affected individual's rehabilitation program.

(3) A diagnosis of alcoholism, chronic alcoholism, alcohol dependency, chronic alcohol abuse, etc., in and of itself, does not satisfy the definition of "disabling effects of chronic alcoholism."

(4) Injury sustained by a veteran as a proximate and immediate result of activity undertaken by the veteran while physically or mentally unqualified to do so due to alcoholic intoxication is not considered a disabling effect of chronic alcoholism.

(5) The disabling effects of chronic alcoholism, which prevent initiation or continuation of participation in a vocational rehabilitation program after November 17, 1988, shall not be considered to be the result of willful misconduct.

(Authority: 38 U.S.C. 1503(b)(1), Pub. L. 100-689)

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[AD-FRL-3778-9]

Standards of Performance for New Stationary Sources Amendments to Subpart J (Petroleum Refineries) and Addition of Performance Specification 7 to Appendix B

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The purpose of this action is five-fold: (1) To require (as opposed to being an option) the monitoring of sulfur dioxide (SO₂) in gases discharged into the atmosphere from the combustion of fuel gases or, as an alternative, the monitoring of hydrogen sulfide (H₂S) in fuel gases; (2) to delete the mention of controlling SO₂ after combustion of fuel gases; (3) to delete the monitoring requirement of H₂S in gases discharged into the atmosphere from Claus sulfur recovery plants, but require the monitoring of other reduced sulfur compounds using continuous emission monitoring systems (CEMS's) or SO₂ CEMS's after oxidizing the reduced sulfur compounds to SO₂; (4) to add Performance Specification (PS) 7 for H₂S CEMS's to Appendix B of this part; and (5) to clarify ambiguities in the existing regulations. All affected fuel gas combustion devices and Claus plants in petroleum refineries, subject to subpart J of 40 CFR part 60, will be required to install and operate CEMS's within 1 year of the promulgation date. These monitoring requirements are not new, but previous H₂S and reduced sulfur CEMS installations were contingent upon the Agency's promulgation of PS's. These amendments were published in the *Federal Register* on March 1, 1989 (54 FR 8564) and April 28, 1989 (54 FR 18308).

DATES: Effective Date: October 2, 1990.

Judicial review. 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.

ADDRESSES: *Docket.* Docket No. A-88-24, containing materials relevant to this rulemaking, is available for public inspection and copying between 8:30 a.m. and 3:30 p.m., Monday through Friday, at EPA's Air Docket Section, 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: Foston Curtis or Roger T. Shigehara, Emission Measurement Branch (MD-19), Technical Support Division, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number (919) 541-1063.

SUPPLEMENTARY INFORMATION:

I. The Rulemaking

The present monitoring requirements for fuel gas combustion devices under § 60.105(a) (3) and (4) allows the options of monitoring SO₂ after fuel gases are combusted or monitoring H₂S in the fuel gases. Since October 6, 1975 (40 FR 46250), affected facilities choosing to monitor H₂S in the fuel gases have been exempted from the monitoring requirements of § 60.105(a)(4) because PS's for H₂S CEMS's had not been established. This rulemaking will amend the emission monitoring requirements to end this exemption. The effect of this rulemaking will be to require affected facilities to monitor SO₂ after fuel gas combustion or, as an alternative, H₂S in the fuel gas.

When fuel gases are burned in a combustion device, the H₂S is converted to SO₂. The resulting SO₂ concentration is substantially less than the corresponding H₂S in the fuel gas due to dilution from added combustion air. The amount of dilution air required for complete fuel gas combustion hinges upon the makeup of fuel gas components (primarily hydrogen and hydrocarbons) and their stoichiometric need for oxygen. The EPA investigated a number of typical fuel gas compositions and their combustion products and determined that, at zero percent excess air, the concentration of SO₂ formed from combusting fuel gas containing H₂S at the standard level (162 ppm) ranged from 9 to 25 ppm with the majority of values between 15 and 20 ppm. This agrees with the 15- to 20-ppm SO₂ level noted in the background document to the proposed petroleum refineries standard.

Realizing the complexity of establishing the SO₂/H₂S equivalency on a case-by-case basis, EPA has selected 20 ppm to represent the compliance level for SO₂. In addition, rather than requiring monitoring of the effluent after each combustion device, EPA is allowing the monitoring of SO₂ after only one of the combustion devices as long as that one location accurately represents the fuel gas being burned by all of the combustion devices.

During 1978 and 1982, EPA conducted evaluations of H₂S CEMS's and concluded that acceptable H₂S CEMS's were not available (see section 4 of PS 7). However, a State agency and a local agency reported that H₂S CEMS's have been installed under their jurisdiction that are operating satisfactorily. Certification test reports that have been submitted for Agency review indicate that, at least in these cases, acceptable CEMS accuracy and calibration drift

(CD) are attainable. Other data from regulatory agencies have shown varying degrees of success in certifying and auditing H₂S CEMS's. Most of these data were taken from H₂S CEMS's of the same type, and instrument performance appears to be linked to operator and maintenance proficiency. Thus, EPA has decided to allow the use of H₂S CEMS's for fuel gases as an alternative to SO₂ CEMS's for combusted fuel gases. For this purpose, PS 7 was proposed.

In reviewing the regulations, EPA determined that the option of controlling SO₂ after combusting the fuel gases was not being used. Also, this option does not appear to be an economically feasible alternative for future consideration. Therefore, mention of this control option is being deleted from the regulation. This action, however, does not prohibit the use of such control devices. In the future, sources that desire to burn fuel gases containing H₂S in excess of 230 mg/dscm and control the resulting SO₂ emissions may petition the Administrator for an alternative compliance demonstration.

Hydrogen sulfide and reduced sulfur emitted from Claus plants are regulated by standards set at 10 and 300 ppm, respectively. Reduced sulfur compounds, though determined separately from H₂S, are also inclusive of H₂S by definition. The Agency has determined that it is difficult to monitor the disproportionate concentrations of H₂S and other reduced sulfur compounds on a continual basis, especially at levels near the standards. Therefore, a separate determination of H₂S apart from other reduced sulfur compounds will not be required, but only the continuous monitoring of reduced sulfur compounds. Performance Specification 5 and Method 15 or 15A will be used to evaluate the reduced sulfur CEMS performance.

For greater flexibility, CEMS that oxidizes the reduced sulfur to SO₂ and analyzes the concentration of the resulting SO₂ will be allowed. Rather than trying to determine the concentration of SO₂ equivalent to the reduced sulfur concentration, EPA will use the level of 250 ppm SO₂ (dry basis, zero percent excess air) to represent the SO₂ compliance level. This concentration is consistent with the control option of combusting the effluent gases under § 60.102(a)(2)(i).

In addition to the above changes, ambiguities in the existing regulations are being clarified by correcting inconsistencies and by specifying pertinent testing procedures that originally were only implied.

This rulemaking does not impose emission measurement requirements

beyond those specified in the current regulations, neither does it change any emission standard nor make it more stringent. Rather, the rulemaking will facilitate the use of acceptable CEMS's and allow affected facilities to comply with monitoring requirements to which they are already subject.

II. Public Participation

The opportunity to hold public hearings at 10 a.m. on March 22, 1989 for the proposed subpart J revisions and May 19, 1989 for proposed PS 7 was presented but no one desired to make an oral presentation. The public comment periods were from March 1 to July 12, 1989 for the subpart J revisions and from April 28 to July 12, 1989 for PS 7.

III. Significant Comments and Changes to the Proposed Rulemaking

Seven comment letters were received from the proposal of the rulemakings. The major comments and responses are summarized in this preamble. Most of the comment letters contained multiple comments. The significant comments and subsequent method changes are listed here.

1. One commenter requested that permeation tube calibration systems and scrubbers be allowed as alternatives to Methods 3, 6, and 11 for span calibration and zero checks of CEMS's. The commenter noted that commercially available systems have been found to be extremely accurate and reliable for fuel gas and Claus plant units and are far superior to older, labor-intensive, wet-chemical procedures.

Approving alternatives for specific calibration systems beyond the EPA reference methods is not within the scope of the rulemaking. Written requests for approval should be submitted to the Director of EPA's Technical Support Division. The request must include a clearly defined procedure that can be uniformly followed, supporting data showing the alternative's comparability to the reference method, and procedures addressing the appropriate quality assurance (QA) measures.

2. Another commenter strongly urged EPA to take a "more reasonable" approach to the exemption from the CO CEMS requirement provided in § 60.105(a)(2)(ii). The following reasons were offered to support this stand:

a. A demonstration that CO emissions are less than 50 ppm was thought to be excessively restrictive. Instead, a limit of 30 percent of the standard should be ample to show that a unit is designed for high-efficiency regeneration and that a CEMS is not warranted.

b. Requiring 30 days of continuous monitoring data to demonstrate a CEMS would not be necessary. Although this may be desirable in some instances, it was recommended that performance test data be allowed in lieu of continuous monitoring data.

c. The language in § 60.105(a)(2)(ii) needs clarifying to require that EPA issue an exemption when the required information is submitted with the written request. As proposed, a lack of response from EPA would leave the owner or operator in an unclear compliance status.

d. It was not clear to the commenter if any additional requirements with the revisions [i.e., CEMS relative accuracy (RA) demonstrations] affect owners or operators who submitted requests for exemption under the existing requirements.

The Method 6 flow rate of 2 liters/min in § 60.105(a)(3)(iii) was questioned. With the Method 6 detection limit at 3.4 mg SO₂ when sampling at 1 liter/min for 20 minutes, it was not understood why a larger sample was needed, since this is approximately 6 percent of the 20 ppm standard. This change was considered an added complication, and it was recommended that it be reconsidered. If this change could be truly justified, some flexibility in the sampling flow rate was requested, such as "approximately 2 liters/min."

Finally, the commenter objected to what was thought to be a change to rolling 3-hour averaging periods for determining compliance with § 60.105(a)(3) and (4). It was noted that no rationale for this change was discussed in the supplementary information, and that this was clearly an added recordkeeping requirement, not a clarification. Current rules were thought to require that monitoring records be kept for 3-hour block periods, of which there are eight per day. A 1986 EPA memorandum to directors of EPA Regional air divisions was cited as evidence of the EPA policy of using block averages. By increasing the requirement to rolling 3-hour periods, the Agency would cause a threefold increase to the recordkeeping burden and a triple counting of any extended periods of excess emissions.

The proposed rule does not change the CEMS-exemption requirements nor the averaging period of the existing regulation. Therefore, comments to these points and any subsequent changes based on the comments are beyond the scope of this rulemaking.

Concerning the issuance of an exemption, the intent of the wording in § 60.105(a)(2)(ii) is to note that the exemption is contingent upon the

Agency's decision after reviewing the submitted demonstration data and exemption request, not upon its submission. Mentioning that an exempted source is not required to perform additional CEMS testing requirements is not necessary since an exemption from monitoring implies that no CEMS will be installed to further test. Under normal situations, a source that has submitted an exemption request is not required to perform additional testing until the Agency makes a decision. In some cases though, the Agency may need to request interim tests. However, if the decision is such that a CEMS must be installed, this CEMS may be subjected to an RA test.

The requirement in § 60.105(a)(3)(iii) to operate Method 6 at 2 liters/min for at least 30 minutes was made to minimize the analytical error that results from measuring small titration volumes. For routine Method 6 analyses, sample titration volumes of at least 2 ml are desired to minimize the error contributed by buret inaccuracy and the averaging of duplicate measurements. To add flexibility and conform with the guidelines given in Method 6, an approximate sampling flow rate of 2 liters/min will be required.

Finally, the requirement for 3-hour rolling SO₂ averages is not a change from current practice. The block averaging period mentioned in the March 1986 memorandum is applicable specifically to determinations of compliance with applicable national air quality standards. Current policy permits emission limits established to comply with such standards to be expressed either as block or rolling averages. The same holds true for compliance with emission control requirements under applicable part 60 standards. In the case in question, the rolling average was the original intent. Thus today's action is not a change from the present requirements.

3. One commenter thought that PS 7 left much to be desired. Basic measures of analyzer performance, such as calibration error, response time, and operational test period were thought to be needed. Having to meet the CD specification on only 6 out of 7 test days would not encourage adjustment of the analyzer when drift exceeds the specification. Compliance with the CD specification without exceptions was preferred, with short-term and zero drift specifications also included. At the very least, language indicating that States may impose additional or more stringent specifications was desired.

The commenter thought that the requirement to report only excess emissions would not allow an agency to

take into account performance during compliance periods when determining enforcement action. Requiring sources to report data for all times periods was favored since a different enforcement action may be appropriate for a source that operates most of the time near the standard than for a source that usually operates well below the standard.

Continual CEMS compliance and Appendix F procedures were not mandated for subpart J sources. The PS test procedures are not designed for long-term evaluation nor for continual compliance but to provide the initial check of the instrument's capabilities at the time of installation. The Agency feels that CEMS data accuracy and representativeness can be demonstrated sufficiently by RA and CD tests. A more in-depth evaluation of the CEMS at the discretion of the operator is encouraged, but this additional testing need not be required since the overall quality of monitor data can be determined by the RA and CD tests.

The RA and CD specifications are determined from studies of CEMS performance over extended periods of time. In an Agency study of H₂S CEMS's, the most reliable instruments were only capable of meeting CD's of 5 percent or less on 6 of 7 test days.

The changing of reporting requirements is beyond the scope of this rulemaking. The purpose of the rulemaking is to revise the subpart J monitoring and testing requirements to add clarity and additional information that were originally left out. This does not include revising the reporting criteria that have become a standard procedure for many source categories. Regulations governing State's authority are neither addressed nor regulated in subpart J but in other sections of the regulations.

4. A commenter noted that the wording change to § 60.104 might be construed to limit the exemption of flare gas associated with emergency malfunction situations. This should be clarified by revising the wording to recognize the fact that process upset gases, even when not the direct result of an "emergency malfunction" (e.g., process unit upsets due to changing feedstock, etc.), must be handled by a flare system for safety considerations. The proposed wording has been clarified to reflect this.

5. Another commenter saw no technical reason why the SO₂ CEMS's should not be used for direct compliance with SO₂ emission limitations at subpart J sources. The proposed revisions were thought to be inconsistent with the subpart Db ruling which uses the same

CEMS's as subpart J for direct compliance. The proposed rule also appeared to conflict with current EPA policy (as suggested in an EPA internal memorandum) of using CEMS data in the enforcement process. Because of the quantity of SO₂ emissions from refineries, and due to past experience with several refineries under the commenter's jurisdiction, the enforcement of continuous compliance with SO₂ emission limitations was thought to be imperative.

The commenter also felt that incinerators following Claus plants should be monitored for temperature and oxygen to ensure total sulfur oxidation to SO₂. It was noted that in § 60.153(b)(3), the operators of incinerators located at sewage treatment plants are required to install, calibrate, maintain, and operate temperature devices. Similar language was desired for subpart J incinerators.

The same commenter questioned the flexibility of spans allowed in § 60.105(a)(1) for opacity CEMS's. The commenter argued that the benefits of additional accuracy refinements do not justify the costs as long as Method 9 remains the sole compliance method. The commenter felt that the arguments for allowing the use of CEMS data in lieu of Method 9 observations for compliance determinations were still valid when the CEMS is properly installed, certified, and maintained in accordance with PS 1 of appendix B. It was argued that the Agency either allow the CEMS data for direct compliance or eliminate the allowance for span flexibility.

It was initially determined when the subpart J regulations were developed that the monitoring data would be used to document excess emissions. This requirement cannot be changed in this rulemaking since such a change would constitute a major action instead of a clarification and would require a separate assessment and proposal with accompanying CEMS QA specifications. The oxidation efficiency of the control device will be documented through Method 15 testing for reduced sulfur compounds, and the added requirements for oxygen and temperature CEMS's will not be necessary.

The use of noncompliance CEMS's in the proposed revisions is not inconsistent with EPA policy mentioned in the memorandum. As noted in the memorandum, data from CEMS's that are not the compliance method "should be used to monitor the continuous compliance of sources and to initiate follow-up action including on-site inspections, requesting further

information, and issuing a notice of violation."

6. A commenter from industry inquired about a situation in which some of their refinery's facilities were required by the EPA Regional Office and the State agency to install CEMS's under applicable Prevention of Significant Deterioration (PSD) and construction permit requirements even though fuel gas combustion devices have been exempted for H₂S monitoring requirements since 1975. Thirteen analyzers were installed at a significant cost. Twelve of these analyzers were installed between 1977 and 1983 during EPA's performance evaluation of H₂S CEMS's. Although EPA concluded that acceptable H₂S CEMS's were not available, the refinery was still required to install whatever analyzers were available at that time. In view of this, the commenter made the following recommendations.

a. The CEMS's that were required to be installed by State or Federal permits prior to the proposal date of the subject rule should be exempt from performance specification test (PST) requirements.

b. The regulations should allow bench testing and certification of the CEMS's by the manufacturer.

c. If a facility has installed more than one CEMS of the same make and manufacturer, only one PST need be conducted to certify the remaining CEMS's. The cost of certifying several identical analyzers is significant and an unnecessary expense.

For CEMS's that have already been installed under Regional Office PSD requirements, exemptions or "grandfathering" of new monitoring requirements must be requested on a case-by-case basis through the Regional Office that Required the initial CEMS installation.

The Agency does not feel that CEMS bench testing and certification by the manufacturer represents a fail-safe means of verifying instrument performance. Manufacturers have a vested interest in the outcome of such evaluations. Bench testing may be routinely done to initially demonstrate the reliability of the instrument to the purchaser. However, this should not be substituted for a complete and observed PST after the CEMS has been installed and is functioning under actual conditions.

All CEMS's that are not monitoring the same process stream will need to be evaluated by PST, regardless of make or manufacturer. Experience has shown that, even with identical CEMS's performance can vary from unit to unit. Factors that affect the performance of

CEMS's include internal malfunctions that may be specific to individual units as well as operational variables that reflect operator technique. The initial performance of each CEMS can only be verified by testing each unit under actual installed conditions.

7. A commenter recommended that an exemption should be allowed when it is demonstrated that the reduced sulfur H₂S emissions from subject Claus units are well below the respective 300 and 10 ppm standard levels during routine and normal operation. With Sulften tail gas treating units, continuous H₂S CEMS's are already utilized and the reduced sulfur was reported to be barely detectable. Unit upsets and upstream operational problems will reflect loss of optimum operating conditions long before any resultant increased emissions exceed the reduced sulfur regulatory limit. Therefore, an exemption from the continuous monitoring of reduced sulfur and oxygen from these sources should be allowed.

In addition, the commenter recommended that the time period for CEMS installation at affected refineries be extended to at least 18 months to allow sufficient time for procurement, installation, and calibration of the instrument. Where H₂S analyzers are employed as standard equipment for Claus recovery plants, the analyzer may serve as the CEMS, provided it passes the PST and reflects representative measurement of emissions. Monitoring exemptions may be considered in those cases where emissions are routinely much lower than the standard and where there is an economic incentive to operate the device to minimize operational problems and upset conditions. Exemptions for devices that meet these conditions are best considered on case-by-case requests since such devices represent a minority of the total in operation.

The Agency does not think an extension of the CEMS installation period is warranted. Affected sources are notified by the proposed rulemaking of the intended monitoring needs. An approximate period of 1 year between regulation proposal and promulgation affords time to survey the CEMS market. In conjunction with the 1-year installation period, this has proven to be adequate.

IV. 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 development.

The docketing system is intended to allow members of the public and industries involved to identify readily 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 revisions 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)).

Under Executive Order 12291, EPA must judge whether a regulation is "major" and, therefore, subject to the requirement of a regulatory impact analysis. The Agency has determined that this rulemaking would not result in any of the adverse economic effects set forth in section 1 of the Order as grounds for finding a "major rule." The Agency has, therefore, concluded that this regulation is not a "major rule" under Executive Order 12291.

The Regulatory Flexibility Act (RFA) of 1980 requires the identification of potentially adverse impacts of Federal regulations upon small business entities. The Act specifically requires the completion of an RFA analysis in those instances where small business impacts are possible. Because this rulemaking imposes no adverse economic impacts, an analysis has not been conducted.

Pursuant to the provisions of 5 U.S.C. 605(b), I hereby certify that the promulgated rule will not have an impact on small entities because no additional costs will be incurred.

This rule does not change any information collection requirements currently approved by OMB under the Paperwork Reduction Act of 1980, 44 U.S.C. 3501 *et seq.* Information requirements contained in 40 CFR part 60, Appendix A are cleared under OMB Control Number 2060-0022.

List of Subjects in 40 CFR Part 60

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

Dated: September 21, 1990.

William K. Reilly,
Administrator.

40 CFR part 60 is amended as follows:

PART 60—[AMENDED]

1. The authority for part 60 continues to read:

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

§ 60.17 [Amended]

2. In § 60.17(a)(56) through (59), mention of "§ 60.106(h)(2)" is revised to read "§ 60.106(j)(2)."

§ 60.103 [Amended]

3. In § 60.103(a), the phrase "gases which contain carbon monoxide in excess of 0.050 percent by volume." is revised to read "gases that contain carbon monoxide (CO) in excess of 500 ppm by volume (dry basis)."

4. In § 60.104, paragraphs (a)(1), (2)(i), and (2)(ii) are revised to read as follows:

§ 60.104 Standards for sulfur oxides.

(a) * * *

(1) Burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H₂S) in excess of 230 mg/dscm (0.10 gr/dscf). The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this paragraph.

(2) * * *

(i) For an oxidation control system or a reduction control system followed by incineration, 250 ppm by volume (dry basis) of sulfur dioxide (SO₂) at zero percent excess air.

(ii) For a reduction control system not followed by incineration, 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (H₂S), each calculated as ppm SO₂ by volume (dry basis) at zero percent excess air.

5. In § 60.105, (a)(1) through (a)(7), (a)(13)(i), (d), and (e) are revised, and (a)(14) is removed to read as follows:

§ 60.105 Monitoring of emissions and operations.

(a) * * *

(1) For fluid catalytic cracking unit catalyst regenerators subject to § 60.102(a)(2), an instrument for continuously monitoring and recording the opacity of emissions into the atmosphere. The instrument shall be spanned at 60, 70, or 80 percent opacity.

(2) For fluid catalytic cracking unit catalyst regenerators subject to § 60.103(a), an instrument for continuously monitoring and recording the concentration by volume (dry basis) of CO emissions into the atmosphere, except as provided in paragraph (a)(2)(ii) of this section.

(i) The span value for this instrument is 1,000 ppm CO.

(ii) A CO continuous monitoring system need not be installed if the owner or operator demonstrates that the average CO emissions are less than 50 ppm (dry basis) and also files a written request for exemption to the

Administrator and receives such an exemption. The demonstration shall consist of continuously monitoring CO emissions for 30 days using an instrument that shall meet the requirements of Performance Specification 4 of Appendix B of this part. The span value shall be 100 ppm CO instead of 1,000 ppm, and the relative accuracy limit shall be 10 percent of the average CO emissions or 5 ppm CO, whichever is greater. For instruments that are identical to Method 10 and employ the sample conditioning system of Method 10A, the alternative relative accuracy test procedure in § 10.1 of Performance Specification 2 may be used in place of the relative accuracy test.

(3) For fuel gas combustion devices subject to § 60.104(a)(1), an instrument for continuously monitoring and recording the concentration by volume (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere (except where an H₂S monitor is installed under paragraph (a)(4) of this section). The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 50 ppm SO₂ and 10 percent oxygen (O₂).

(ii) The SO₂ monitoring level equivalent to the H₂S standard under § 60.104(a)(1) shall be 20 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 and 3 shall be used for conducting the relative accuracy evaluations. Method 6 samples shall be taken at a flow rate of approximately 2 liters/min for at least 30 minutes. The relative accuracy limit shall be 20 percent or 4 ppm, whichever is greater, and the calibration drift limit shall be 5 percent of the established span value.

(iv) Fuel gas combustion devices having a common source of fuel gas may be monitored at only one location (i.e., after one of the combustion devices), if monitoring at this location accurately represents the SO₂ emissions into the atmosphere from each of the combustion devices.

(4) In place of the SO₂ monitor in paragraph (a)(3) of this section, an instrument for continuously monitoring and recording the concentration (dry basis) of H₂S in fuel gases before being burned in any fuel gas combustion device.

(i) The span value for this instrument is 425 mg/dscm H₂S.

(ii) Fuel gas combustion devices having a common source of fuel gas may

be monitored at only one location, if monitoring at this location accurately represents the concentration of H₂S in the fuel gas being burned.

(iii) The performance evaluations for this H₂S monitor under § 60.13(c) shall use Performance Specification 7. Method 11 shall be used for conducting the relative accuracy evaluations.

(5) For Claus sulfur recovery plants with oxidation control systems or reduction control systems followed by incineration subject to § 60.104(a)(2)(i), an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of SO₂ emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air.

(i) The span values for this monitor are 500 ppm SO₂ and 10 percent O₂.

(ii) The performance evaluations for this SO₂ monitor under § 60.13(c) shall use Performance Specification 2. Methods 6 and 3 shall be used for conducting the relative accuracy evaluations.

(6) For Claus sulfur recovery plants with reduction control systems not followed by incineration subject to § 60.104(a)(2)(ii), an instrument for continuously monitoring and recording the concentration of reduced sulfur and O₂ emissions into the atmosphere. The reduced sulfur emissions shall be calculated as SO₂ (dry basis, zero percent excess air).

(i) The span values for this monitor are 450 ppm reduced sulfur and 10 percent O₂.

(ii) The performance evaluations for this reduced sulfur (and O₂) monitor under § 60.13(c) shall use Performance Specification 5, except the calibration drift specification is 2.5 percent of the span value rather than 5 percent. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations. If Method 3 yields O₂ concentrations below 0.25 percent during the performance specification test, the O₂ concentration may be assumed to be zero and the reduced sulfur CEMS need not include an O₂ monitor.

(7) In place of the reduced sulfur monitor under paragraph (a)(6) of this section, an instrument using an air or O₂ dilution and oxidation system to convert the reduced sulfur to SO₂ for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of the resultant SO₂. The monitor shall include an oxygen monitor for correcting the data for excess oxygen.

(i) The span values for this monitor are 375 ppm SO₂ and 10 percent O₂

(ii) For reporting purposes, the SO₂ exceedance level for this monitor is 250 ppm (dry basis, zero percent excess air).

(iii) The performance evaluations for this SO₂ (and O₂) monitor under § 60.13(c) shall use Performance Specification 5. Methods 15 or 15A and Method 3 shall be used for conducting the relative accuracy evaluations.

* * * * *

(13) * * *

(i) The test methods as described in § 60.106(k);

* * * * *

(d) For any fluid catalytic cracking unit catalyst regenerator under § 60.102 that uses an incinerator-waste heat boiler to combust the exhaust gases from the catalyst regenerator, the owner or operator shall record daily the rate of combustion of liquid or solid fossil-fuels (liters/hr or kg/hr) and the hours of operation during which liquid or solid fossil-fuels are combusted in the incinerator-waste heat boiler.

(e) For the purpose of reports under § 60.7(c), periods of excess emissions that shall be determined and reported are defined as follows:

Note: All averages, except for opacity, shall be determined as the arithmetic average of the applicable 1-hour averages, e.g., the rolling 3-hour average shall be determined as the arithmetic average of three contiguous 1-hour averages.

(1) *Opacity.* All 1-hour periods that contain two or more 6-minute periods during which the average opacity as measured by the continuous monitoring system under § 60.105(a)(1) exceeds 30 percent.

(2) *Carbon monoxide.* All 1-hour periods during which the average CO concentration as measured by the CO continuous monitoring system under § 60.105(a)(2) exceeds 500 ppm.

(3) *Sulfur dioxide from fuel gas combustion.* (i) All rolling 3-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(3) exceeds 20 ppm (dry basis, zero percent excess air); or

(ii) All rolling 3-hour periods during which the average concentration of H₂S as measured by the H₂S continuous monitoring system under § 60.105(a)(4) exceeds 230 mg/dscm (0.10 gr/dscf).

(4) *Sulfur dioxide from Claus sulfur recovery plants.* (i) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(5) exceeds 250 ppm (dry basis, zero percent excess air); or

(ii) All 12-hour periods during which the average concentration of reduced sulfur (as SO₂) as measured by the

reduced sulfur continuous monitoring system under § 60.105(a)(6) exceeds 300 ppm; or

(iii) All 12-hour periods during which the average concentration of SO₂ as measured by the SO₂ continuous monitoring system under § 60.105(a)(7) exceeds 250 ppm (dry basis, zero percent excess air).

6. In § 60.106, paragraphs (a) through (d) are revised, paragraphs (e) through (h) are redesignated as (g) through (j), and new paragraphs (e), (f) and (k) are added to read as follows:

§ 60.106 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b).

(b) The owner or operator shall determine compliance with the particulate matter (PM) standards in § 60.102(a) as follows:

(1) The emission rate (E) of PM shall be computed for each run using the following equation:

$$E = \frac{K c_s Q_{sd}}{R_c}$$

where:

E=Emission rate of PM, kg/1000 kg (lb/1000 lb) of coke burn-off.

c_s=Concentration of PM, g/dscm (lb/dscf).

Q_{sd}=Volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

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

K=Conversion factor, 1.0 (kg²/g)/(1000 kg) [10³ lb/(1000 lb)].

(2) Method 5 shall be used to determine the concentration (c_s) of PM and volumetric flow rate (Q_{sd}) of the effluent gas. The sampling time and sample volume for each run shall be at least 60 minutes and 0.90 dscm (31.8 dscf).

(3) The coke burn-off rate (R_c) shall be computed for each run using the following equation:

$$R_c = K_1 Q_r (\%CO_2 + \%CO) K_2 Q_a - K_3 Q_r$$

$$[(\%CO/2) + \%CO_2 + \%O_2]$$

where:

R_c=Coke burn-off rate, kg/hr (1000 lb/hr).

Q_r=Volumetric flow rate of exhaust gas from catalyst regenerator before entering the emission control system, dscm/min (dscf/min).

Q_a=Volumetric flow rate of air to FCCU regenerator, as determined from the fluid catalytic cracking unit control room instrumentation, dscm/min (dscf/min).

%CO₂ = Carbon dioxide concentration, percent by volume (dry basis).

%CO = Carbon monoxide concentration, percent by volume (dry basis).

%O₂ = Oxygen concentration, percent by volume (dry basis).

K₁ = Material balance and conversion factor, 0.2982 (kg-min)/(hr-dscm-%) [0.0186 (lb-min)/(hr-dscf-%)].

K₂ = Material balance and conversion factor, 2.086 (kg-min)/(hr-dscm-%) [0.1303 (lb-min)/(hr-dscf-%)].

K₃ = Material balance and conversion factor, 0.0994 (kg-min)/(hr-dscm-%) [0.0062 (lb-min)/(hr-dscf-%)].

(i) Method 2 shall be used to determine the volumetric flow rate (Q_v).

(ii) The emission correction factor, integrated sampling and analysis procedure of Method 3 shall be used to determine CO₂, CO, and O₂ concentrations.

(4) Method 9 and the procedures of § 60.11 shall be used to determine opacity.

(c) If auxiliary liquid or solid fossil-fuels are burned in an incinerator-waste heat boiler, the owner or operator shall determine the emission rate of PM permitted in § 60.102(b) as follows:

(1) The allowable emission rate (E_a) of PM shall be computed for each run using the following equation:

$$E_a = 1.0 + A (H/R_c) K'$$

where:

E_a = Emission rate of PM allowed, kg/1000 kg (lb/1000 lb) of coke burn-off in catalyst regenerator.

1.0 = Emission standard, kg coke/1000 kg (lb coke/1000 lb).

A = Allowable incremental rate of PM emissions, 0.18 g/million cal (0.10 lb/million Btu).

H = Heat input rate from solid or liquid fossil fuel, million cal/hr (million Btu/hr).

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

K' = Conversion factor to units of standard, 1.0 (kg²/g)/(1000 kg) [10³ lb/(1000 lb)].

(2) Procedures subject to the approval of the Administrator shall be used to determine the heat input rate.

(3) The procedure in paragraph (b)(3) of this section shall be used to determine the coke burn-off rate (R_c).

(d) The owner or operator shall determine compliance with the CO standard in § 60.103(a) by using the integrated sampling technique of Method 10 to determine the CO concentration (dry basis). The sampling time for each run shall be 60 minutes.

(e) The owner or operator shall determine compliance with the H₂S standard in § 60.104(a)(1) as follows: Method 11 shall be used to determine the H₂ concentration. The gases entering the sampling train should be at about atmospheric pressure. If the pressure in the refinery fuel gas lines is relatively

high, a flow control valve may be used to reduce the pressure. If the line pressure is high enough to operate the sampling train without a vacuum pump, the pump may be eliminated from the sampling train. The sample shall be drawn from a point near the centroid of the fuel gas line. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf). Two samples of equal sampling times shall be taken at about 1-hour intervals. The arithmetic average of these two samples shall constitute a run. For most fuel gases, sampling times exceeding 20 minutes may result in depletion of the collection solution, although fuel gases containing low concentrations of H₂S may necessitate sampling for longer periods of time.

(f) The owner or operator shall determine compliance with the SO₂ and the H₂S and reduced sulfur standards in § 60.104(a)(2) as follows:

(1) Method 6 shall be used to determine the SO₂ concentration. The concentration in mg/dscm (lb/dscf) obtained by Method 6 is multiplied by 0.3754 to obtain the concentration in ppm. The sampling point in the duct shall be the centroid of the cross section if the cross-sectional area is less than 5.00 m² (54 ft²) or at a point no closer to the walls than 1.00 m (39 in.) if the cross-sectional area is 5.00 m² or more and the centroid is more than 1 m from the wall. The sampling time and sample volume shall be at least 10 minutes and 0.010 dscm (0.35 dscf) for each sample. Eight samples of equal sampling times shall be taken at about 30-minute intervals. The arithmetic average of these eight samples shall constitute a run. Method 4 shall be used to determine the moisture content of the gases. The sampling point for Method 4 shall be adjacent to the sampling point for Method 6. The sampling time for each sample shall be equal to the time it takes for two Method 6 samples. The moisture content from this sample shall be used to correct the corresponding Method 6 samples for moisture. For documenting the oxidation efficiency of the control device for reduced sulfur compounds, Method 15 shall be used following the procedures of paragraph (f)(2) of this section.

(2) Method 15 shall be used to determine the reduced sulfur and H₂S concentrations. Each run shall consist of 16 samples taken over a minimum of 3 hours. The sampling point shall be the same as that described for Method 6 in paragraph (f)(1) of this section. To ensure minimum residence time for the sample inside the sample lines, the sampling rate shall be at least 3.0 lpm (0.10 cfm). The SO₂ equivalent for each run shall be calculated after being

corrected for moisture and oxygen as the arithmetic average of the SO₂ equivalent for each sample during the run. Method 4 shall be used to determine the moisture content of the gases as the paragraph (f)(1) of this section. The sampling time for each sample shall be equal to the time it takes for four Method 15 samples.

(3) The oxygen concentration used to correct the emission rate for excess air shall be obtained by the integrated sampling and analysis procedure of Method 3. The samples shall be taken simultaneously with the SO₂, reduced sulfur and H₂S, or moisture samples. The SO₂, reduced sulfur, and H₂S samples shall be corrected to zero percent excess air using the equation in paragraph (h)(3) of this section.

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

(1) Methods 6, 6B, or 8 are used. The sampling location(s) are the same as those specified for the monitor.

(2) 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 16 valid samples is required to obtain one valid day of data.

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

(4) For Method 8, the procedures as outlined in this section are used. The equivalent of 16 hours of sampling is required to obtain one valid day of data.

§ 60.106 [Amended]

7. In newly redesignated § 60.106(h) (3), (4), and (5), mention of "§ 60.106(f)(2)," "§ 60.106(f)(1)," or "(f)" is revised to read "§ 60.106(h)(2)," "§ 60.106(h)(1)," or "(h)," respectively.

§ 60.106 [Amended]

8. In newly redesignated § 60.106(i), (i)(2)(i), and (i)(7), mention of "(g)(12)," "§ 60.106(g)(3)," or "(g)(6)" is revised to read "(i)(12)," "§ 60.106(i)(3)," or "(i)(6)," respectively.

§ 60.106 [Amended]

9. In newly redesignated § 60.106(i)(7), "(a)(4)" is revised to read "(b)(3)."

§ 60.106 [Amended]

10. In newly redesignated § 60.106(j)(3)(ii), "(h)(2)" is revised to read "(j)(2)."

§ 60.107 [Amended]

11. In § 60.107(b)(1)(ii), "(a)(14)" is revised to read "§ 60.106(k)."

§ 60.107 [Amended]

12. In § 60.107(b)(2), "§ 60.106(g)(12)" is revised to read "§ 60.106(i)(12)."

§ 60.107 [Amended]

13. In § 60.107(c)(1)(i), "§ 60.106(f)" is revised to read "§ 60.106(h)."

§ 60.107 [Amended]

14. In § 60.107(c)(1)(ii), "§ 60.106(g)" in both places is revised to read "§ 60.106(i)."

§ 60.107 [Amended]

15. In § 60.107(c)(1)(iii), "§ 60.106(h)" is revised to read "§ 60.106(j)."

§ 60.108 [Amended]

16. In § 60.108(d), "§ 60.106(g) or (h)" is revised to read "§ 60.106(i) or (j)."

§ 60.109 [Amended]

17. In § 60.109(b)(2), "60.106(g)(12)" is revised to read "60.106(i)(12)."

18. In Appendix B, by adding Performance Specification 7 to read as follows:

Appendix B—Performance Specifications

* * * * *

Performance Specification 7—
Specifications and Test Procedures for
Hydrogen Sulfide Continuous Emission
Monitoring Systems in Stationary
Sources

1. Applicability and Principle

1.1 *Applicability.* 1.1.1 This specification is to be used for evaluating the acceptability of hydrogen sulfide (H₂S) continuous emission monitoring systems (CEMS's) at the time of or soon after installation and whenever specified in an applicable subpart of the regulations.

1.1.2 This specification is not designed to evaluate the installed CEMS performance over an extended period of time nor does it identify specific calibration techniques and other auxiliary procedures to assess CEMS performance. The source owner or operator, however, is responsible to calibrate, maintain, and operate the CEMS. To evaluate CEMS performance, the Administrator may require, under Section 114 of the Act, the source owner or operator to conduct CEMS performance evaluations at other times besides the initial test. See § 60.13(c).

1.1.3 The definitions, installation specifications, test procedures, data reduction procedures for determining calibration drifts (CD) and relative accuracy (RA), and reporting of Performance

Specification 2 (PS 2), Sections 2, 3, 5, 6, 8, and 9 apply to this specification.

1.2 *Principle.* Reference method (RM), CD, and RA tests are conducted to determine that the CEMS conforms to the specification.

2. Performance and Equipment Specifications

2.1 *Instrument zero and span.* This specification is the same as Section 4.1 of PS 2.

2.2 *Calibration drift.* The CEMS calibration must not drift or deviate from the reference value of the calibration gas or reference source by more than 5 percent of the established span value for 6 out of 7 test days (e.g., the established span value is 300 ppm for subpart J fuel gas combustion devices).

2.3 *Relative accuracy.* The RA of the CEMS shall be no greater than 20 percent of the mean value of the RM test data in terms of the units of the emission standard or 10 percent of the applicable standard, whichever is greater.

3. Relative Accuracy Test Procedure

3.1 *Sampling Strategy for RM Tests.* Correlation of RM and CEMS Data Number of RM Tests, and Calculations. These are the same as that in PS 2, § 7.1, 7.2, 7.3, and 7.5, respectively.

3.2 *Reference Methods.* Unless otherwise specified in an applicable subpart of the regulation, Method 11 is the RM for this PS.

4. Bibliography

1. U.S. Environmental Protection Agency. Standards of Performance for New Stationary Sources; Appendix B; Performance Specifications 2 and 3 for SO₂, NO_x, CO₂, and O₂ Continuous Emission Monitoring Systems; Final Rule. 48 CFR 23608. Washington, DC U.S. Government Printing Office. May 25, 1983.

2. U.S. Government Printing Office. Gaseous Continuous Emission Monitoring Systems—Performance Specification Guidelines for SO₂, NO_x, CO₂, O₂, and TRS. U.S. Environmental Protection Agency. Washington, D.C. EPA-450/3-82-026. October 1982. 26p.

3. Maines, G.D., W.C. Kelly (Scott Environmental Technology, Inc.), and J.B. Homolya. Evaluation of Monitors for Measuring H₂S in Refinery Gas. Prepared for the U.S. Environmental Protection Agency. Research Triangle Park, N.C. Contract No. 68-02-2707. 1978. 60 p.

4. Ferguson, B.B., R.E. Lester (Harmon Engineering and Testing), and W.J. Mitchell. Field Evaluation of Carbon Monoxide and Hydrogen Sulfide Continuous Emission Monitors at an Oil Refinery. Prepared for the U.S. Environmental Protection Agency. Research Triangle Park, N.C. Publication No. EPA-600/4-82-054. August 1982. 100 p.

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DEPARTMENT OF TRANSPORTATION**Coast Guard****46 CFR Part 16**

[CGD 86-067d]

RIN 2115-AC45

Programs for Chemical Drug and Alcohol Testing of Commercial Vessel Personnel

AGENCY: Coast Guard, DOT.

ACTION: Final rule.

SUMMARY: This final rule revises the pre-employment drug testing requirement for two categories of marine employers: Large employers (those having more than 50 employees) and medium employers (those having from 11 to 50 employees). This change will minimize the need for additional pre-employment testing by these large and medium employers until December 1990 and relieve them of an unintended economic burden caused by implementation of pre-employment testing before the implementation of random testing.

EFFECTIVE DATE: This rule is effective October 2, 1990.

FOR FURTHER INFORMATION CONTACT: Lieutenant Commander T. A. Murphy, Project Manager, Marine Investigation Division (G-MMI), Office of Marine Safety, Security and Environmental Protection, U.S. Coast Guard Headquarters, 2100 Second Street, SW., Washington, DC 20593-0001, (202) 267-2215.

SUPPLEMENTARY INFORMATION: When deciding on appropriate exceptions to pre-employment testing requirements, the Department of Transportation was reviewing drug program rules for six different operating modes. The modal rules generally provided an exception to pre-employment testing for employees who had been covered for a full year by a random testing program conducted by their previous employer. It was the Department's intent that after passing a pre-employment test, employees would be covered by an employer's random testing program and would not need additional pre-employment testing when they changed jobs.

Many large marine employers began pre-employment testing as early as May 1, 1989. Medium employers began pre-employment testing on the December 21, 1989 implementation date. The current Coast Guard regulations provide that maritime personnel subject to an employer's random testing program continuously for the previously twelve months may be excepted from a pre-employment test when changing jobs. Coast Guard random testing was

postponed in response to the Court's decision in *Transportation Institute, et al. v. U.S. Coast Guard*, No 88-3429 (D.D.C., Dec. 18, 1989).

Therefore, until the promulgation of random drug testing regulations, an employee will not be able to use the random program exception from pre-employment testing. Thus, maritime employees who change jobs need to have evidence that they have passed a pre-employment drug test within the past six months in order to be hired without an additional pre-employment drug test.

The January 8, 1990 pre-employment revision (55 FR 634) extended the effective date of some pre-employment tests to relieve the unintended economic burden of repeated testing. At that time, over 20,000 employees of large marine employers had been pre-employment tested since May 1989 at a cost of slightly over one million dollars. While precise figures are not available at this time, since January 1990, additional new employees of both large and medium marine employers have been pre-employment tested. Without a further extension of the effective date for pre-employment tests, these employees will all have to be retested if they change jobs.

The Coast Guard, therefore, is revising § 16.205(a) to provide that employees who have successfully passed a pre-employment test between May 1, 1989 and June 21, 1989, may be deemed to have passed a pre-employment test on June 21, 1990 and therefore, until December 21, 1990, will not need to have further pre-employment testing when they change jobs. The Coast Guard also is revising § 16.205(b) to provide the same benefit to medium employers. These changes will minimize the need for additional pre-employment testing by large and medium employers relieving them of an unintended economic burden.

This rule relieves employers of the unintended economic and administrative burden of additional testing. The Coast Guard finds that notice and public comment are not necessary. Requiring notice and comment would unduly delay the relief sought to be provided by this rule and would, therefore, be contrary to the public interest, and good cause exists under 5 U.S.C. 553(b) to publish this rule without notice and comment. As provided in 5 U.S.C. 553(d)(1), this rule relieves a restriction and may be made effective less than 30 days after publication in the *Federal Register*. The rule will be effective immediately upon publication in the *Federal Register*.

Regulatory Assessment

This final rule revises the requirements for pre-employment testing by medium and large marine employers in the final rule published on November 21, 1988, as modified on June 23, 1989 and on January 8, 1990. It does not change the basic regulatory structure of that rule. Based on currently reported costs of about \$50 per test, this revision will relieve medium and large marine employers of an economic burden in excess of one million dollars over the next six months.

Regulatory Flexibility Determination

The amendments in this final rule modify the requirements for pre-employment testing for large employers (who have more than 50 employees) and medium employers (who have between 11 and 50 employees). Pre-employment testing requirements for small employers are not affected. Therefore, the Coast Guard certifies that this final rule will not have a significant economic impact on a substantial number of small entities.

Paperwork Reduction Act

This final rule does not amend the recordkeeping and reporting requirements of the final rule published on November 21, 1988.

Environmental Assessment

The Coast Guard has considered the environmental impact of this amendment to the rules promulgated on November 21, 1988, and concluded that, under section 2.B.2.1. of Commandant Instruction M16475.1B, they are categorically excluded from further environmental documentation.

Federalism Implications

In accordance with Executive Order 12612, the Coast Guard has determined that this final rule does not have sufficient federalism implications to warrant preparation of a Federalism Assessment.

List of Subjects in 46 CFR Part 16

Seamen, Marine safety, Navigation (Water), Alcohol and alcoholic beverages, Drugs.

Final Rule

For the reasons set forth in the preamble, title 46, chapter I, of the Code of Federal Regulations is amended as follows:

PART 16—[AMENDED]

1. The authority citation for part 16 continues to read as follows:

Authority: 46 U.S.C. 2103, 3306, 7101, 7301 and 7701; 49 CFR 1.46.

2. Section 16.205 is amended by revising paragraphs (a) and (b) to read as follows:

§ 16.205 Implementation of chemical testing programs.

(a) Each employer who employs more than 50 employees required to be tested under this part implemented the pre-employment testing program required in § 16.210 not later than July 21, 1989. An employee who passed a pre-employment test under these rules during the period between May 1, 1989, and June 21, 1990, shall be deemed to have successfully passed a pre-employment test on June 21, 1990. All other employer testing programs required by this part, except the random testing program which has been suspended until further notice, were implemented not later than December 21, 1989.

(b) Each employer who employs from 11 to 50 employees required to be tested under this part implemented the pre-employment, serious marine incident and reasonable cause testing programs required by this part not later than December 21, 1989. An employee who has passed a pre-employment test under these rules in the period between October 1, 1989 and June 21, 1990, shall be deemed to have successfully passed a pre-employment test on June 21, 1990.

Dated: September 27, 1990.

J.D. Sipes,

Rear Admiral, U.S. Coast Guard, Chief, Office of Marine Safety, Security and Environmental Protection.

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FEDERAL COMMUNICATIONS COMMISSION

47 CFR Part 80

[PR Docket No. 89-524; FCC 90-309; RM-6554]

Use of Narrow-Band Direct-Printing (NB-DP) Frequencies in the Maritime Services

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: This rule would require applicants to submit a showing of need to obtain new or additional narrow-band direct-printing (NB-DP) frequencies. This action was initiated by a petition for rule making (RM-6554) filed September 27, 1988, by Mobile