DEPARTMENT OF THE INTERIOR

Minerals Management Service

30 CFR Part 250

RIN 1010–AC85

Oil and Gas and Sulphur Operations in the Outer Continental Shelf (OCS) Fixed and Floating Platforms and Documents Incorporated by Reference

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Notice of proposed rulemaking.

SUMMARY: We are proposing to amend our regulations to address floating offshore platforms that, until now, have not been expressly covered. These floating production systems (FPSs) are variously described as column-stabilized units (CSUs); floating production, storage and offloading facilities (referred to by industry as ''FPSOs''); tension-leg platforms (TLPs); spars, etc. We are also incorporating into our regulations a body of industry standards pertaining to FPSs, and this will save the public the costs of developing separate, and in many cases unnecessarily duplicative, government standards. However, it will increase costs to industry by making certain independent third-party reviews mandatory, particularly by requiring hazards analyses for all new FPSs.

DATES: We will consider all comments we receive by February 25, 2002. We will begin reviewing comments then and may not fully consider comments we receive after February 25, 2002.

ADDRESSES: If you wish to comment, you may submit your comments by any one of several methods. You may mail or hand-carry comments (three copies) to the Department of the Interior; Minerals Management Service; Mail Stop 4024; 381 Elden Street; Herndon, Virginia 20170–4817; Attention: Rules Processing Team. You may also comment via e-mail to rules.comments@mms.gov. Please submit e-mail comments as an ASCII file (MS Word) avoiding the use of special characters and any form of encryption. Include your name and return address in your e-mail message and mark your message for return receipt. Show the Rule Identification Number (RIN 1010–AC–85) in your subject line.

Mail or hand-carry comments with respect to the information collection burden of the proposed rule to the Office of Information and Regulatory Affairs; Office of Management and Budget; Attention: Desk Officer for the Department of the Interior (OMB control number 1010–XXXX); 725 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Carl Anderson, Physical Scientist, at (703) 787–1608; or Joseph Levine, Chief, Operations Analysis Branch, at (703) 787–1033 or FAX (703) 787–1555.

SUPPLEMENTARY INFORMATION: We propose incorporating into our regulations a body of industry standards pertaining to FPSs, and this will save the public the costs of developing Government standards. It will also enhance the efficient exploration and development of the most promising new sources of United States oil and gas supplies in the deepwater areas of the Gulf of Mexico (GOM).

Incorporating the now-voluntary industry standards into our regulations would dictate that respondents comply with the requirements in the incorporated documents. This includes certified verification agent (CVA) reviews and hazards analyses for some areas that current regulations do not require, but the voluntary standards recommend. Thus, the now-voluntary CVA reviews and hazards analyses would become mandatory. This would increase the number of CVA nominations and reports associated with the facilities and require hazards analysis documentation for new floating platforms. (In some of the industry standards, the CVA is referred to as an independent verification agent (IVA)). Also, industry sources estimate that it will cost an average of $1.2 million to apply hazards analysis to each new floating production facility. Requiring the industry hazards analysis standard for all new deepwater floating production platforms will be the most costly element of the proposed rule.

Deepwater areas of the GOM have shown a remarkable increase in oil and gas exploration, development, and production. In part this is due to the development of new technologies that (1) enable drilling and production in deeper waters; and (2) reduce operational costs and risks, such as new geophysical software used to identify highly productive reservoirs. In 1993, deepwater areas of the GOM (water depths greater than 1,000 feet, or 305 meters) accounted for only 12 percent and 2 percent, respectively, of total GOM oil and gas production. Discovery and development of deepwater fields began accelerating in 1994, so that by the end of 1999, deepwater areas of the GOM accounted for 45 percent and 17 percent, respectively, of total GOM oil and gas production. (From 1994 through 1998, deepwater production of oil rose 260 percent.)

To realize just how important the new deepwater areas of the GOM are to United States energy supplies, it is helpful to compare the productivity of deepwater wells to past wells in more shallow waters. Historically, GOM wells generally have produced between 200 and 300 barrels (bbls.) per day. However, at least one existing deepwater well is producing over 30,000 bbls. of oil per day, and several are producing over 20,000 bbls. per day. An existing deepwater platform in the GOM is producing 140,000 bbls. of oil and 140 million cubic feet of gas per day. Success in deepwater is evident in both the high production rates and sustained drilling for new discoveries announced each year. Drilling is expected to move into water depths of 10,000 feet (3,048 meters).

The following discussion is intended to give the reviewer an idea of how fast technological changes are occurring in deepwater oil and gas operations. It is also meant to establish the urgency for MMS to adopt common industry standards so that system designers will know what is acceptable when they plan for floating deepwater platforms. Any of the drilling or production ''records'' discussed below will likely be exceeded by the time this Notice is published. Several notable examples show how new deepwater exploration and production systems are ''leap-frogging'' the technical achievements of their recent predecessors.

As of December 2000, there were 40 rigs drilling in water depths greater than 305 meters (1,000 feet), versus 32 for December 1999. This represents a record number of rigs drilling in deepwater. Until now, about 100 deepwater discoveries have been announced for the GOM.

Concerning exploratory drilling in August 1998, Chevron U.S.A. set a GOM water-depth record in 7,718 feet of water (2,352 meters) on Atwater Valley Block 118, 175 miles southeast of New Orleans. But Chevron's record was recently exceeded, (1) in the GOM by Broken Hill Proprietary Petroleum, which drilled an exploratory well in 8,835 feet (2,693 meters) of water in the Walker Ridge area; and (2) offshore Brazil, where PetroBras set a new 9,111-foot (2,777-meter) world record.

Concerning production water-depth records, Petrobras holds the water-depth record for sustained production at their Roncador field in the Campos Basin with the Petrobras 36 column stabilized floating production system installed in 6,079 feet (1,853 meters) of water. Subsea wells tie back to Petrobras 36 in

6,560 feet (1,999 meters) of water, which is a world production depth record.

So far, only 21 permanent development platforms have been installed in waters over 1,000 feet deep (305 meters) in the GOM. Seven of these structures are fixed platforms, three are compliant towers, eight are TLPs, and three are spars. All of these production platforms were approved on a case-by-case basis under existing MMS regulations. However, it would streamline the permitting process and increase the up-front net-present-value of deepwater projects for the offshore industry if MMS had a designated body of standards to specifically deal with the whole new class of floating production platforms. The offshore oil and gas industry has already developed its own body of standards because of the recognized need to streamline the design process for floating platform facilities and their subsystems. In addition to describing the primary platform facilities, the industry standards also govern production and pipeline risers, stationkeeping and mooring systems, flexible pipelines, and hazards analysis.

A discussion of the expense involved in exploring for and developing deepwater oil and gas reserves was presented at the World Petroleum Congress (WPC) in Calgary, Canada, in June 2000. According to the ''Oil & Gas Journal,'' Mr. Luiz Rodolfo Landim Machado of Petroleo Brasileiro SA projected that through 2004, the oil industry would spend about $76 billion in deepwater areas worldwide to explore for and develop about 19 billion barrels of oil equivalent. He indicated that about 27 percent of the reserves would be found in the GOM. (''WPC: Deepwater holds industry's greatest challenges, opportunities,'' Vol. 98, Issue 26 (June 26, 2000).) Assuming a commensurate expenditure of 27 percent, that would lead to the oil industry spending $20.5 billion in deepwater areas of the GOM through 2004. That represents industry deepwater expenditures of over $4.5 billion per year from June 2000 through 2004.

To provide further background on the potential impact of this proposal, leases lying in water depths of from 400 to 800 meters (from 1,312 to 2,625 feet) have lease terms of 8 years, as opposed to the customary 5-year term. Leases lying in water depth of over 800 meters (2,625 feet) have 10-year terms. These longer lease terms give lessees much longer time horizons to plan their lease development activities. Consequently, the MMS GOM Region estimates that about six FPSs will be approved for installation during any given year. This means that probably much fewer than even half of the approximately 98 companies currently holding leases in deepwater would ever submit development plans for a floating platform before their lease terms expire.

The Purpose of this Rule

The purpose of this proposed rule is to incorporate into our regulations a body of industry standards that will enable us to more efficiently examine plans for and issue permits for floating offshore platforms. Our regulations currently do not specifically cover these facilities. Therefore, this proposal includes a complete rewrite of subpart I of 30 CFR Part 250 to cover floating platforms. Incorporating the voluntary industry standards would save the public the cost of developing government-specific standards. It would also enhance the efficient exploration and development of the most promising new sources of United States oil and gas supplies in the deepwater areas of the GOM in two ways. First, it would provide more certainty to the lessees' design engineers so that they would know in advance what design criteria are acceptable to MMS. Second, it would enhance MMS engineers' efforts in reviewing each new project to ensure structural integrity, operational and human safety, and environmental protection. This is because the proposed regulation would establish a single body of standards on which each new project would be based. These enhancements would streamline the regulatory review process and, thereby, increase the net-present-value of the project to lessees that assume the high financial risks of developing deepwater areas. There can be considerable costs to the industry if revenues from the project are delayed while industry and government engineers haggle over acceptable standards for the project in question.

Under existing MMS regulations, lessees and operators have to use standards that are acceptable to MMS or they will not receive a permit to proceed with their development plans. If they do not choose to use standards that we have already incorporated, they have the option to use equivalent standards, provided they first obtain our approval.

Many industry standards reference ''second-tier documents'' that we do not directly incorporate into our regulations. Nevertheless, the fact that an industry standard relies on second-tier documents effectively makes them part of the justification for approving a permit. It is incumbent upon MMS and the certified verification agent (CVA) to make certain that referenced standards are properly followed. MMS has operated under this premise for years, and it has worked well. However, the system usually works more efficiently when an industry standard is directly incorporated by reference into our regulations. That way, lessees do not have to go through the steps of obtaining our approval for various standards prior to developing their plans. Also, it saves MMS time, because we do not have to conduct special reviews of certain industry standards with which we may be unfamiliar.

The 1996 National Technology Transfer and Advancement Act (NTTAA) (Pub. L. 104–113) directs Federal agencies to achieve greater reliance on voluntary standards and standards-developing organizations by participating in developing voluntary standards without dominating the process. The NTTAA encourages ''the use by Federal agencies of private sector standards, emphasizing where possible the use of standards developed by private, consensus organizations.'' This is for the purpose of ''eliminating unnecessary duplication and complexity in the development and promulgation of conformity assessment requirements and measures'' (i.e., standards and regulations). Office of Management and Budget (OMB) Circular A–119 specifies the requirements for Federal agencies to implement the NTTAA. According to Circular A–119, agencies must use domestic and international voluntary consensus standards in their regulatory and procurement activities instead of government standards, unless use of consensus standards would be inconsistent with applicable law or otherwise impractical. Agencies have the discretion to decline to use existing voluntary consensus standards if they determine that such standards are inconsistent with applicable law or otherwise impractical.

In this proposed rulemaking, MMS intends to incorporate eight American Petroleum Institute (API) standards, and one American Welding Society (AWS) standard. In one case, we would be adopting the latest edition of an API standard already incorporated into MMS regulations. We have actively participated in developing several of these standards and believe that we could not write duplicative government regulations that would be either as technically detailed or as broad in their scope as these standards. Moreover, the writing of such duplicative government regulations could neither be done in a timely nor economically efficient way—nor could it be done with the same level of expertise that was involved in the industry effort. We believe that it is entirely within the letter and spirit of the NTTAA that we incorporate these voluntary industry standards into our regulations. Moreover, we believe it is in the public interest that we so adopt these standards.

The nine industry standards proposed for incorporation are as follows:

(1) *API Recommended Practice 2A (API RP 2A)—WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design; Twenty-First Edition, December 2000, API Order No. G2AWSD.* The 19th and 20th editions of this standard are already incorporated by reference into MMS regulations. The 21st edition would simply update and replace these two earlier editions. The 21st edition provides the rationale for revising much of subpart I—Platforms and Structures—in the proposed rulemaking. It deals with bottom-founded structures which, until this rulemaking, have been the primary focus of Subpart I. Upon the effective date of the final rule, the following National Notices to Lessees and Operators (NTLs) related to API RP 2A would be cancelled: (1) NTL No. 98–1N provides interim guidance for applying platform design criteria from API RP 2A; and (2) NTL No. 98–4N provides interim guidance for applying the ''Simplified Fatigue Analysis Procedure'' from API RP 2A. These two NTLs had been published in cooperation with the API RP 2A workgroup. The workgroup had discovered some insufficient design criteria in both the 19th and 20th editions of RP 2A related to various structures and the water depths in which they were to be constructed. Depending on the type of structure, either the 19th or 20th edition was the correct standard to be used. The NTLs provided guidance on the correct use of the standards.

(2) *API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998, API Stock No. G02RD1.* This standard covers drilling, production, and pipeline risers associated with all FPSs, including spars, TLPs, CSUs, and FPSOs. Moreover, it deals with construction of flexible riser systems, which have not been explicitly covered under MMS regulations.

(3) *API RP 2SK, Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures, Second Edition, December 1996, Effective Date: March 1, 1997, API Stock No. G02SK2.* Again, stationkeeping systems for floating platforms have not been explicitly covered under MMS regulations.

(4) *API RP 2T, Recommended Practice for Planning, Designing, and Constructing Tension Leg Platforms, Second Edition, August 1997, API Order No. G02T02.* Over the past 13 years, every application for a TLP installation in the GOM OCS has relied on API RP 2T as the basis for its design. MMS has approved each of these applications on a case-by-case basis. There are now eight such installations in the deepwater areas of the GOM. For all practical purposes, API RP 2T is the de facto industry guideline on the design and construction of TLPs. In some areas, API RP 2T relies very heavily on the analysis contained in API RP 2A, particularly for environmental loading and foundation and anchoring factors. Considered by itself, API RP 2T imposes no new reporting requirements or third-party review requirements.

(5) *API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, First Edition, Sept. 1, 1993, API Stock No. 811–07200.* Implementing this standard for all new deepwater floating production platforms will be the most costly element of the proposed rule. This is a standard that has provided much of the early rationale and background for MMS's voluntary Safety and Environmental Management Planning program. During 2000, a consensus was reached within the industry that the complexities and safety issues involved in FPSs warrant the imposition of this standard to all new FPSs, variously described as CSUs, TLPs, spars, and FPSOs, etc. Deepwater FPSs are the most complex systems on the OCS and can include numerous production wells that flow at over 20,000 barrels per day. Therefore, we have concluded that new floating production facilities should be assigned the highest priority for conducting hazards analysis. This analysis should follow one or more of the methods described in API RP 14J. Further, we believe it is most efficient to address potential safety and environmental hazards during the facility design phase. (Hazards analysis is much less useful and less cost-effective when applied to facilities that are already installed.) We would require an analysis of operational hazards to be included as integral parts of all Deepwater Operations Plans. Industry sources estimate that it will cost an average of $1.2 million to apply API RP 14J hazards analysis in the design of each new floating production facility.

(6) *API Specification (Spec) 17J, Specification for Unbonded Flexible Pipe, Second Edition, November 1999, Effective Date: July 1, 2000, API Stock No. G17J02.* For several years MMS has been permitting remote subsea wells that use flexible pipe for deep sea production pipelines. We believe that this standard adequately serves the interests of environmental protection and safety in providing guidance to both regulators and industry in the proper design and construction of flexible pipelines and flowlines. The industry projects that as many as 50 percent of future deepwater wells will be remote subsea wells tied back to existing production platforms. Also, there will be an increasing number of shallow water subsea tie-backs. Therefore, this standard will be essential for future production operations.

(7) *AWS D3.6M:1999, Specification for Underwater Welding.* MMS refers to this document every time we receive an application for an underwater welding repair. This document is analogous and complimentary to the AWS Standard D1.1 (Structural Welding Code-Steel) which is used for above-water welding. Both AWS D1.1 and AWS D1.4 (Structural Welding Code-Reinforcing Steel) have been incorporated into our regulations for over 20 years. Further, MMS was a member of the subcommittee which developed AWS D3.6M. It serves a definite purpose in our reassessment process. Underwater welding is used infrequently because of the expenses involved in making such repairs. However, it has been used with great success over the years to solve several complex underwater repair problems, some in very deep water. We receive applications for underwater welding repairs on an infrequent basis; but AWS D3.6M is the primary document the industry follows for these purposes. We need to incorporate it into our regulations, because we anticipate a growing future need for underwater welding repairs. Considered by itself, AWS D3.6M imposes no new reporting requirements or third-party review requirements.

(8) *API RP 2FPS, Recommended Practice for Planning, Designing, and Constructing Floating Production Systems, First Edition, March 2001, API Order No. G2FPS1.* RP 2FPS serves as an ''umbrella document'' for all FPSs, except for TLPs (covered by API RP 2T). It incorporates as second-tier standards the requirements of API RP 2RD, API RP 2SK, API RP 14J, API Spec 17J, and those of other standards. Considered by itself, API RP 2FPS imposes no new reporting requirements or third-party review requirements.

(9) *API RP 2SM, Recommended Practice for Design, Manufacture,*

Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, API Order No. G02SM1. This is a new API RP that addresses an important component of offshore mooring systems. To date, synthetic fiber ropes have not been used in the mooring systems of floating OCS platforms and have seen only limited use for similar applications worldwide. Therefore, given the lack of long-term experience with the use of synthetic fiber rope, API RP 2SM will serve as the primary MMS document of reference for use in approving applications which propose the use of such mooring systems. MMS was a member of the API subcommittee which developed API RP 2SM.

Regulatory Changes in Addition to Documents Incorporated by Reference

In addition to incorporating new industry documents, the proposed rule would include language specific to FPSs. This language complements the December 16, 1998, Memorandum of Understanding (MOU) between MMS and the U.S. Coast Guard (USCG) that we published in the **Federal Register** on January 15, 1999 (64 FR 2660–2667). The MOU describes our respective and overlapping responsibilities for regulating ''Floating Outer Continental Shelf (OCS) Facilities.''

In response to issues raised by the International Association of Drilling Contractors (IADC) and Noble Drilling Services, Inc., we propose to insert new language to address our regulatory responsibilities under the MOU. We propose to insert the language into subpart H, at § 250.800(b), and subpart I at proposed § 250.904(e). The IADC and Noble Drilling Services had commented on an MMS **Federal Register** Notice of June 21, 2000 (65 FR 38453). In reviewing our third-party review requirements in that Notice, they expressed concern that we did not adequately clarify the differences between our responsibilities and those of the USCG. MMS and the USCG have overlapping responsibilities under the MOU, so it is not possible to completely eliminate ambiguities in our regulations.

We stated above that the 21st edition of API RP 2A provides the rationale for revising and shortening much of Subpart I—Platforms and Structures—in the proposed rulemaking. With the incorporation of the 21st edition, we can eliminate much of the verbiage in the current subpart I regulations. Therefore, we propose to rename and totally reorganize subpart I.

On July 7, 2000, we published a proposed rule concerning decommissioning activities (65 FR 41892). We assume that the decommissioning rule will be finalized before this rule. Therefore, we have written proposed § 250.913 to correspond to relevant sections of the decommissioning activities proposed rule. If, for any reason, the decommissioning rule does not become final before this rule, § 250.913 will be rewritten in the final rule to correspond to the status of 30 CFR part 250 at the time of publication.

Derivation Table

The following derivation table shows where the proposed requirements originate from in the current 30 CFR 250, subpart I, regulations.

Proposed new section	Current regulation section
§ 250.900 What general requirements apply to fixed and floating platforms?	§ 250.900; New requirement.
§ 250.901 What industry standards must fixed and floating platforms meet?	§ 250.900(g); § 250.907(b), (c), (d); § 250.908 (b), (c), (d), (e); New requirements.
§ 250.902 What must an application to approve a fixed, or floating platform contain?	§ 250.901(a), (b)
§ 250.903 Which of my platforms, associated structures, and major modifications are subject to the Platform Verification Program?	250.902; New requirements.
§ 250.904 If my platform, associated structure, or major modification is subject to the Platform Verification Program, what must I do?	§ 250.902; New requirements.
§ 250.905 What plans must I submit under the Platform Verification Program?	§ 250.902; New requirements.
§ 250.906 When must I resubmit Platform Verification Program plans?	§ 250.902; New requirements.
§ 250.907 When must I combine Platform Verification Program plans?	§ 250.902; New requirements.
§ 250.908 How do I nominate a CVA?	§ 250.902; § 250.903(b).
§ 250.909 What are the CVA's primary responsibilities?	§ 250.903(a).
§ 250.910 What are the CVA's primary duties during the design phase?	§ 250.903(a)(1).
§ 250.911 What are the CVA's primary duties during the fabrication phase?	§ 250.903(a)(2).
§ 250.912 What are the CVA's primary duties during the installation phase?	§ 250.903(a)(3).
§ 250.913 What are the minimum structural fatigue requirements?	§ 250.907(c).
§ 250.914 What records must I keep for all primary structural members?	§ 250.907(a).
§ 250.915 Where must I locate foundation boreholes?	New requirements.
§ 250.916 What in-service inspection requirements must I meet?	§ 250.912(b); New requirements.
§ 250.917 What are the requirements for fixed or floating platform removal and location clearance?	§ 250.913
§ 250.918 What records must I keep?	§ 250.914

Procedural Matters

Public Comment Procedures

Our practice is to make comments, including names and home addresses of respondents, available for public review during regular business hours. Individual respondents may request that we withhold their home address from the rulemaking record, which we will honor to the extent allowable by law. There may be circumstances in which we would withhold from the rulemaking record a respondent's identity, as allowable by law. If you wish us to withhold your name and/or address, you must state this prominently at the beginning of your comment. However, we will not consider anonymous comments. We will make all submissions from organizations or businesses, and from individuals identifying themselves as representatives or officials of organizations or businesses, available for public inspection in their entirety.

Regulatory Planning and Review (Executive Order 12866)

This document is not a significant rule and is not subject to review by OMB under Executive Order 12866.

(1) The proposed rule will not have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities. The overall effect of the proposed rule will not create an adverse effect upon the ability of the United States offshore oil and gas industry to compete in the world marketplace, nor will the proposal adversely affect investment or employment factors locally. (Indeed, of the 98 lessees who hold leases in deepwater and, therefore, could be affected by the proposed rule, 19 are foreign multinational corporations.) The economic analysis prepared for this proposed rule indicates that the estimated regulatory costs would be about $3 million for a ''generic'' floating platform having 10 production risers, 2 pipeline risers, a mooring system, and 80 miles of pipelines. This represents less than 1 percent of the total cost of the facility. Assuming that plans for 6 such facilities were submitted for approval in any given year, the total annual regulatory cost to the offshore oil and gas industry would be about $18 million [$3,000,000 x 6 = $18 million]. The economic analysis for this proposed rule is available from the Department of the Interior; Minerals Management Service; Operations Analysis Branch; Mail Stop 4022; 381 Elden Street; Herndon, Virginia 20170–4817; Attention: Carl W. Anderson.

(2) This rule will not create inconsistencies with other agencies' actions. This rule does not change the relationships of the OCS oil and gas leasing program with other agencies' actions. These relationships are all encompassed in agreements and memorandums of understanding that will not change with this proposed rule.

(3) This rule does not alter the budgetary effects or entitlements, grants, user fees, or loan programs or the rights or obligations of their recipients.

(4) This rule does not raise novel legal or policy issues. There are precedents for actions of this type under past lease stipulations and regulations dealing with oil spill response and oil spill financial responsibility provisions under the OCS Lands Act and the Oil Pollution Act of 1990.

Regulatory Flexibility (RF Act)

The Department certifies that this document will not have a significant economic effect on a substantial number of small entities under the RF Act (5 U.S.C. 601 *et seq.*). The economic analysis prepared for this rule concluded that not more than two small deepwater lessees would submit plans for floating platforms in any given year. Most likely, these lessees would join in as partners in a single application for a floating platform. To the extent that these lessees participate in such joint ventures, the costs imposed by the proposed rule on individual operators would be reduced significantly. Therefore, we conclude that the rule would not have a significant economic impact on a substantial number of small entities.

For the purposes of this section a ''small entity'' is considered to be an individual, limited partnership, or small company, considered to be at ''arm's length'' from the control of any parent companies, with fewer than 500 employees. Mid-size and large corporations and partnerships under their direct control have access to lines of credit and internal corporate cash flows that are not available to the ''small entity.'' Some of the operators MMS regulates under the OCS oil and gas leasing program would be considered small entities. They are generally represented by the North American Industry Classification System Code 211111, which represents crude petroleum and natural gas extractors.

Of the 98 lessees that have deepwater leases, as many as 26 may be considered to be small. These 26 lessees represent about 33 percent of all small operators on the OCS. Of the 26, only 2 hold 100-percent interest in their deepwater leases. These two lessees have annual revenues such that they would have little difficulty in meeting the requirements of the proposed rule. In all other cases, the small lessees have reduced their deepwater economic risks by being in partnership with other lessees. Sixteen of these lessees hold less than 50-percent interest in their deepwater leases.

Your comments are important. The Small Business and Agriculture Regulatory Enforcement Ombudsman and 10 Regional Fairness Boards were established to receive comments from small business about Federal agency enforcement actions. The Ombudsman will annually evaluate the enforcement activities and rate each agency's responsiveness to small business. If you wish to comment on the enforcement actions of MMS, call toll-free (888) 734–3247.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This rule is not a major rule under (5 U.S.C. 804(2)), SBREFA. This rule:

(a) Does not have an annual effect on the economy of $100 million or more.

(b) Will not cause a major increase in costs or prices for consumers, individual industries, Federal, State, or local government agencies, or geographic regions.

(c) Does not have significant adverse effects on competition, employment, investment, productivity, innovation, or ability of United States-based enterprises to compete with foreign-based enterprises. (Of the 98 lessees who hold leases in deepwater and, therefore, could be affected by the proposed rule, 19 are foreign multinational corporations.)

The economic analysis prepared for this rule concluded that not more than two small deepwater lessees would submit plans for floating platforms in any given year. Most likely, these lessees would join in as partners in a single application for a floating platform. To the extent that these lessees participate in such joint ventures, the costs imposed by the proposed rule on individual operators would be reduced significantly. Therefore, we conclude that the rule would not have a significant economic impact on a substantial number of small entities.

Paperwork Reduction Act (PRA) of 1995

The proposed revisions to sections in subparts A and B of 30 CFR 250 do not affect the information collection (IC) aspects of those regulations. These are currently approved under OMB control numbers 1010–0114 (subpart A) and 1010–0049 (subpart B). We did not submit an information collection request (ICR) to OMB for these sections.

With respect to the proposed revisions in 30 CFR part 250, subparts H, I, and J, we have submitted an ICR (form OMB 83–I) to OMB for review and approval according to section 3507(d) of the PRA. The title of the collection of information is ''Proposed Rulemaking—30 CFR part 250, Subparts J, H, and I, Fixed and Floating Platforms and Structures.'' The ICR covers only the proposed changes to subparts H and J. Because subpart I would be revised in its entirety, the ICR does cover the burden for all of subpart I.

Potential respondents are approximately 130 Federal OCS lessees and operators and CVAs or other third-party reviewers of fixed and floating platforms. Responses are mandatory. The frequency of response varies by section, but is primarily on occasion or annual. The IC does not include questions of a sensitive nature. We will protect information considered proprietary according to 30 CFR 250.196 (Data and information to be made available to the public) and 30 CFR part 252 (OCS Oil and Gas Information Program).

MMS will use the information collected and records maintained under subpart I to determine the structural integrity of all fixed and floating platforms and to ensure that such integrity will be maintained throughout the useful life of these structures. The information is necessary to determine that platforms and structures are sound and safe for their intended purpose and the safety of personnel and pollution prevention. MMS will use the proposed information collected under subparts H and J to ensure proper construction of production safety systems and pipelines.

Although the proposed regulations would specifically cover floating platforms as well as fixed platforms, this is not a new category of IC. MMS has always permitted floating facilities on a case-by-case basis. Incorporating the new documents provides industry with specific standards by which we will hold them accountable in the design, fabrication, and installation of fixed and floating platforms offshore. Making mandatory these now voluntary standards would dictate that respondents comply with the requirements in the incorporated documents. This includes CVA review for some areas that current regulations do not require, but the voluntary standards recommend. The proposed regulations will increase the number of CVA nominations and reports associated with the facilities and require hazards analysis documentation for new floating platforms.

A separate proposed rulemaking on 30 CFR part 250, subpart Q, Decommissioning Activities (published on July 7, 2000, 65 FR 41892) would relocate the platform and structure removal and site clearance requirements from current subpart I regulations to the new subpart Q. The hour burdens for those paperwork requirements were included in the OMB approval of the IC requirements of that rulemaking (1010–0142) and are not included in this submission.

OMB has approved the IC required by current regulations in subparts H, I, and J under control numbers 1010–0059, 1010–0058 and 1010–0050. We estimate the proposed changes will increase the currently approved hour burdens by:

3,300	hours for subpart H
4,320	hours for subpart I
1,800	hours for subpart J
9,420	total burden hour increase

The proposed rule eliminates the notice requirement currently in § 250.901(e) on transporting the platform to the installation site, and the departure request in § 250.912(a) on platform inspection intervals. This reporting change results in a decrease of 570 annual burden hours.

The following chart details the IC burden for the new requirements in subparts H and J and all of the requirements in subpart I. New subpart I requirements are so noted.

Citation 30 CFR 250 proposed section	Reporting or recordkeeping requirement	Hour burden per response or record (hours)
Subpart H		
800(b)	Submit CVA documentation under API RP 2RD. (Estimate 60 per year)	50
803(b)(2)(iii)	Submit CVA documentation under API RP 17J. (Estimate 6 per year)	50
Subpart I		
900(a); 901(b); 902; 903; 905; 907	Submit application to install new fixed or floating platform or significant changes to approved applications, including use of alternative codes, rules, or standards; and Platform Verification Program plans for design, fabrication and installation of new, fixed, bottom-founded, pile-supported, or concrete-gravity platforms and new floating platforms.	24
900(a)(2); 903(c); 906	Submit application for major modification to any platform	24
900(a)(4)	Notify MMS within 24 hours of damage and emergency repairs and request approval of repairs.	16
900(a)(5)	Submit application for the conversion of the use of an existing mobile offshore drilling unit (MODU).	24
901(a)(6), (a)(7), (a)(8)	NEW: Submit CVA documentation under API RP 2RD, API RP 2SK, and API RP 2SM. (Estimate 6 per year).	100
901(a)(10)	NEW: Submit hazards analysis documentation under API RP 14J. (Estimate 6 per year).	500
904(c); 908	Submit nomination and qualification statement for CVA	16
910(c), (d)	Submit interim and final CVA reports and recommendations on design phase	200
911(d), (e), (f)	NEW: Submit interim and final CVA reports and recommendations on fabrication phase, including notice of fabrication procedure changes or design specification modifications. (Estimate 6 per year).	60
912(c), (d), (e)	NEW: Submit interim and final CVA reports and recommendations on installation phase, including notice of any discrepancies or damage to structural members. (Estimate 6 per year).	60
914; 918: See footnote*	Recordkeeping: Record origin and relevant material test results of all primary structural materials; retain records during all stages of construction. Compile, retain, and make available to MMS for the functional life of platform, the as-built drawings, design assumptions/analyses, summary of nondestructive examination records, and inspection results.	50

Citation 30 CFR 250 proposed section	Reporting or recordkeeping requirement	Hour burden per response or record (hours)
916	Develop in-service inspection plan and submit annual (November 1 of each year) report on inspection of fixed or floating platforms, including summary of testing results.	45
900 thru 918	General departure and alternative compliance requests not specifically covered elsewhere in subpart I regulations.	2
	Subpart J	
1002(b)(4); 1007(a)(4)	Submit CVA documentation under API RP 17J. (Estimate 12 per year)	100
1002(b)(5)	Submit CVA documentation under API RP 2RD. (Estimate 12 per year)	50

*The records required are such that respondents would retain them as a usual and customary business practice. The burden would be to make them available to MMS for review.

As part of our continuing effort to reduce paperwork and respondent burdens, MMS invites the public and other Federal agencies to comment on any aspect of the reporting burden in the proposed rule. You may submit your comments directly to the Office of Information and Regulatory Affairs, OMB. Please send a copy of your comments to MMS so that we can summarize written comments and address them in the final rule preamble. Refer to the ADDRESSES section for mailing instructions.

The PRA provides that an agency may not conduct or sponsor a collection of information unless it displays a currently valid OMB control number. Until OMB approves the collection of information and assigns a control number, you are not required to respond. The PRA requires OMB to make its decision on the information collection aspects of this proposed rule between 30 to 60 days after publication in the **Federal Register**. Therefore, a comment to OMB is best assured of having its full effect if OMB receives it by January 28, 2002. This does not affect the deadline for the public to comment to MMS on the proposed regulations.

a. We specifically solicit comments on the following questions:

(1) Is the proposed collection of information necessary for MMS to properly perform its functions, and will it be useful?

(2) Are the estimates of the burden hours of the proposed collection reasonable?

(3) Do you have any suggestions that would enhance the quality, clarity, or usefulness of the information to be collected?

(4) Is there a way to minimize the information collection burden on those who are to respond, including the use of appropriate automated electronic, mechanical, or other forms of information technology?

b. In addition, the PRA requires agencies to estimate the total annual reporting and recordkeeping ‘‘non-hour’’ cost burden resulting from the collection of information. We have not identified any and solicit your comments on this item. For reporting and recordkeeping only, your response should split the cost estimate into two components: (1) The total capital and startup cost component, and (2) annual operation, maintenance, and purchase of services component. Your estimates should consider the costs to generate, maintain, and disclose or provide the information. You should describe the methods you use to estimate major cost factors, including system and technology acquisition, expected useful life of capital equipment, discount rate(s), and the period over which you incur costs. Generally, your estimates should not include equipment or services purchased: before October 1, 1995; to comply with requirements not associated with the information collection; for reasons other than to provide information or keep records for the Government; or as part of a usual and customary business or private practice.

Federalism (Executive Order 13132)

According to Executive Order 13132, this rule does not have Federalism implications. This rule would not substantially or directly affect the relationship between the Federal and State governments, because it deals strictly with technical standards that the offshore oil and gas industry must use in designing, fabricating, and installing floating offshore facilities. This rule would not impose costs on States or localities, nor would it require any action on the part of States or localities.

Takings Implications Assessment (Executive Order 12630)

According to Executive Order 12630, the rule does not have significant Takings implications. A Takings Implication Assessment is not required. Based on our Paperwork Burden analysis and our economic analysis for this proposed rule, the annual incremental cost of complying with this regulation for approximately 98 businesses will be about $190,000 per business, per year. This incremental cost will be absorbed by an industry sector where (1) operating costs just for a contract drilling unit to drill a single well can exceed $1,750,000 per week, and (2) the cost of a deepwater platform can exceed $1 billion. We do not believe that paying this cost will result in any takings. Thus, the Department of the Interior does not need to prepare a Takings Implication Assessment under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights. The proposed rule would not take away or restrict a lessee’s right to develop an OCS oil and gas lease according to the lease terms.

Energy Supply, Distribution, or Use (Executive Order 13211)

This rule is not a significant rule and is not subject to review by the Office of Management and Budget under Executive Order 13211. The rule does not have a significant effect on energy supply, distribution, or use, because it would streamline the regulatory review process and, thereby, enhance the development and production of energy resources from deepwater areas of the OCS. It would do this by specifying a single body of approved industry standards so that lessees would know in advance which design criteria are acceptable to MMS for deepwater production operations. The proposed rule would also simplify MMS engineers’ efforts in reviewing each new project to ensure structural integrity, operational and human safety, and environmental protection. This would be beneficial for increasing energy resources and would provide more certainty to OCS lessees who assume the high financial risks of developing deepwater areas.

Clarity of This Regulation (Executive Order 12866)

Executive Order 12866 requires each agency to write regulations that are easy to understand. We invite your comments on how to make this proposed rule easier to understand, including answers to questions such as the following:

(1) Are the requirements in the rule clearly stated?

(2) Does the rule contain technical language or jargon that interferes with its clarity?

(3) Does the format of the rule (grouping and order of sections, use of headings, paragraphing, etc.) aid or reduce its clarity?

(4) Would the rule be easier to understand if it were divided into more (but shorter) sections?

(5) Is the description of the rule in the **SUPPLEMENTARY INFORMATION** section of this preamble helpful in understanding the rule? What else can we do to make the rule easier to understand?

Send a copy of any comments that concern how we could make this rule easier to understand to: Office of Regulatory Affairs, Department of the Interior, Room 7229, 1849 C Street, NW., Washington, DC 20240. You may also e-mail the comments to this address: *Exsec@ios.doi.gov.*

Civil Justice Reform (Executive Order 12988)

According to Executive Order 12988, the Office of the Solicitor has determined that this rule does not unduly burden the judicial system and meets the requirements of sections 3(a) and 3(b)(2) of the Order.

National Environmental Policy Act (NEPA)

This rule does not constitute a major Federal action significantly affecting the quality of the human environment. We have analyzed this rule under the criteria of the NEPA and 516 Departmental Manual 6, Appendix 10.4C(1). We completed a Categorical Exclusion Review for this action on November 20, 2000, and concluded that ''the proposed rulemaking does not represent an exception to the established criteria for categorical exclusion; therefore, preparation of an environmental analysis or environmental impact statement will not be required.''

Unfunded Mandate Reform Act (UMRA) of 1995

This rule does not impose an unfunded mandate on State, local, or tribal governments or the private sector of more than $100 million per year. The rule does not have a significant or unique effect on State, local or tribal governments or the private sector. A statement containing the information required by the UMRA (2 U.S.C. 1531 *et seq.*) is not required.

List of Subjects in 30 CFR Part 250

Continental shelf, Environmental impact statements, Environmental protection, Government contracts, Incorporation by reference, Investigations, Mineral royalties, Oil and gas development and production, Oil and gas exploration, Oil and gas reserves, Penalties, Pipelines, Public lands—mineral resources, Public lands—rights-of-way, Reporting and recordkeeping requirements, Sulphur development and production, Sulphur exploration, Surety bonds.

Dated: December 3, 2001.

J. Steven Griles,

Acting Assistant Secretary, Land and Minerals Management.

For the reasons stated in the preamble, the Minerals Management Service (MMS) proposes to amend 30 CFR part 250 as follows:

PART 250—OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF

1. The authority citation for part 250 continues to read as follows:

Authority: 43 U.S.C. 1331, *et seq.*

2. In § 250.105, the definition for ''facility,'' is revised to read as follows:

§ 250.105 Definitions.

* * * * *

Facility means: (1) As used in § 250.130, all installations permanently or temporarily attached to the seabed on the OCS (including manmade islands and bottom-sitting structures). They include mobile offshore drilling units (MODUs) or other vessels engaged in drilling or downhole operations, used for oil, gas or sulphur drilling, production, or related activities. They include all floating production systems (FPSs), variously described as column-stabilized-units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc. They also include facilities for product measurement and royalty determination (e.g. lease Automatic Custody Transfer Units, gas meters) of OCS production on installations not on the OCS. Any group of OCS installations interconnected with walkways, or any group of installations that includes a central or primary installation with processing equipment and one or more satellite or secondary installations is a single facility. The Regional Supervisor may decide that the complexity of the individual installations justifies their classification as separate facilities.

(2) As used in § 250.303, means all installations or devices permanently or temporarily attached to the seabed. They include mobile offshore drilling units (MODUs), even while operating in the ''tender assist'' mode (i.e. with skid-off drilling units) or other vessels engaged in drilling or downhole operations. They are used for exploration, development, and production activities for oil, gas, or sulphur and emit or have the potential to emit any air pollutant from one or more sources. They include all floating production systems (FPSs), including column stabilized units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc. During production, multiple installations or devices are a single facility if the installations or devices are at a single site. Any vessel used to transfer production from an offshore facility is part of the facility while it is physically attached to the facility.

(3) As used in § 250.417(b), means a vessel, a structure, or an artificial island used for drilling, well completion, well-workover, or production operations.

(4) As used in §§ 250.900 through 250.918, means all installations or devices permanently or temporarily attached to the seabed. They are used for exploration, development, and production activities for oil, gas, or sulphur and emit or have the potential to emit any air pollutant from one or more sources. They include all floating production systems (FPSs), including column stabilized units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc. During production, multiple installations or devices are a single facility if the installations or devices are at a single site. Any vessel used to transfer production from an offshore facility is part of the facility while it is physically attached to the facility.

* * * * *

3. In § 250.198, in the table in paragraph (e), the following changes are made:

A. Remove entries for API RP 2A, 19th Edition; API RP 2A–WSD, 20th

Edition; and API RP 2A–WSD, 20th Edition, Supplement 1.

B. Add entries in alphanumerical order for API RP 2A–WSD, API RP 2FPS; API RP 2RD, API RP 2SK, API RP 2SM; API RP 2T, API RP 14J, API Spec 17J, and AWS D3.6M:1999 as set forth below:

C. Revise entries for ACI Standard 318–95, ACI 357R–84, AISC Standard Specification for Structural Steel Buildings, ASTM Standard C 33–99a, ASTM Standard C 94/C 94M–99, ASTM Standard C 150–99, ASTM Standard C 330–99, ASTM Standard C 595–98, AWS D1.1–96, AWS D1.4–79, NACE Standard MR0175–99 and NACE Standard RP 01–76–94.

§ 250.198 Documents incorporated by reference.

* * * * *

(e) * * *

Title of documents	Incorporated by reference at
* * * *	* * *
ACI Standard 318–95, Building Code Requirements for Reinforced Concrete, plus Commentary on Building Code Requirements for Reinforced Concrete (ACI 318R–95).	§ 250.901(a)(1).
ACI 357R–84, Guide for the Design and Construction of Fixed Offshore Concrete Structures, 1984.	§ 250.901(a)(2).
AISC Standard Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, June 1, 1989, with Commentary.	§ 250.901(a)(3).
* * * *	* * *
API RP 2A—WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design; Twenty-first Edition, December 2000, API Order No. G2AWSD.	§ 250.901(a)(4).
* * * *	* * *
API RP 2FPS, Recommended Practice for Planning, Designing, and Constructing Floating Production Systems, First Edition, March 2001, API Order No. G2FPS1.	§ 250.901(a)(5).
API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998, API Stock No.G02RD1.	§ 250.800(b); § 250.901(a)(6); § 250.1002(b)(5).
API RP 2SK, Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures, Second Edition, December 1996, Effective Date: March 1, 1997, API Stock No. G02SK2.	§ 250.800(b); § 250.901(a)(7).
API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, API Order No. G02SM1.	§ 250.901(a)(8).
API RP 2T, Planning, Designing and Constructing Tension Leg Platforms, Second Edition, August 1997, Order No. G02T02.	§ 250.901(a)(9).
* * * *	* * *
API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, First Edition, Sept. 1, 1993, API Stock No. 811–07200.	§ 250.800(b); § 250.803(a); § 250.901(a)(10).
* * * *	* * *
API Spec 17J, Specification for Unbonded Flexible Pipe, Second Edition, November 1999, Effective Date: July 1, 2000, API Stock No. G17J02.	§ 250.803(b)(2)(iii); § 250.1002(b)(4); § 250.1007(a)(4).
* * * *	* * *
ASTM Standard C 33–99a, Standard Specification for Concrete Aggregates	§ 250.901(a)(11).
ASTM Standard C 94/C 94M–99, Standard Specification for Ready-Mixed Concrete.	§ 250.901(a)(12).
ASTM Standard C 150–99, Standard Specification for Portland Cement	§ 250.901(a)(13).
ASTM Standard C 330–99, Standard Specification for Lightweight Aggregates for Structural Concrete.	§ 250.901(a)(14).
ASTM Standard C 595–98, Standard Specification for Blended Hydraulic Cements.	§ 250.901(a)(15).
AWS D1.1–96, Structural Welding Code—Steel, 1996, including Commentary	§ 250.901(a)(16).
AWS D1.4–79, Structural Welding Code—Reinforcing Steel, 1979	§ 250.901(a)(17).
AWS D3.6M:1999, Specification for Underwater Welding	§ 250.901(a)(18).
NACE Standard MR0175–99, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, Revised January 1999, NACE Item No. 21302.	§ 250.417(p)(2); § 250.901(a)(19).
NACE Standard RP 01–76–94, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production.	§ 250.901(a)(20).

4. In § 250.204, paragraph (a)(2) is revised to read as follows:

§ 250.204 Development and Production Plan.

(a) * * *

(2) A description of any drilling vessels, fixed or floating platforms, pipelines, or other facilities and operations located offshore which are proposed or known by the lessee (whether or not owned or operated by

the lessee) to be directly related to the proposed development. The description must include the location, size, design, and important safety, pollution prevention, and environmental monitoring features of the facilities and operations. Floating production systems (FPSs) include column-stabilized units (CSUs); floating production, storage, and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc.

* * * * *

5. In § 250.800, the introductory paragraph is redesignated as paragraph (a), and a new paragraph (b) is added to read as follows:

§ 250.800 General requirements.

* * * * *

(b) For all new floating production systems (FPSs) (e.g., column-stabilized units (CSUs); floating production, storage and offloading facilities (FPSOs); tension-leg platforms (TLPs); spars, etc.), you, the lessee, must do all of the following:

(1) Comply with API RP 14J;

(2) Meet the drilling and production riser standards of API RP 2RD;

(3) Meet the production-safety systems requirements contained in this subpart;

(4) Design all stationkeeping systems for floating facilities to meet the standards of API RP 2SK, as well as relevant U.S. Coast Guard regulations; and

(5) Design stationkeeping systems for floating facilities to meet structural requirements in subpart I, §§ 250.900 through 250.918 of this part.

6. In § 250.803, paragraph (a) is revised and paragraph (b)(2)(iii) is added to read as follows:

§ 250.803 Additional production system requirements.

(a) For all new floating production platforms, you must comply with API RP 14J. For all production platforms, you must comply with the following production safety system requirements, in addition to the requirements of § 250.802 and the requirements of API RP 14C.

(b) * * *

(2) * * *

(iii) If you are installing flowlines constructed of unbonded flexible pipe on a floating platform, you must comply with the requirements of API Spec 17J, including its third-party review standards for independent verification agents (IVAs). You must submit your IVA reviews for flowlines constructed of unbonded flexible pipe for review by the MMS District Supervisor.

* * * * *

7. Subpart I and its title are revised to read as follows:

Subpart I—Fixed and Floating Platforms and Structures

Sec.

Subpart I—Fixed and Floating Platforms and Structures

§ 250.900 What general requirements apply to fixed and floating platforms?

(a) You must design, fabricate, install, inspect, and maintain all fixed and floating platforms, and related structures on the Outer Continental Shelf (OCS) so as to ensure their structural integrity for the safe conduct of drilling, workover, and production operations. In doing this, you must consider the specific environmental conditions at the platform location. You must submit an application under § 250.902 and obtain the approval of the Regional Supervisor before installing any platform or performing any of the other activities described in the following table:

Activity	Conditions to be met for application
(1) Install a platform	You must adhere to the requirements of this subpart, including the industry standards in § 250.901
(2) Make a major modification to any platform	Major modifications are any structural changes that materially alter the approved plan or cause a major deviation from approved operations. They are subject to the requirements of this subpart, including the industry standards in § 250.901
(3) Make a major repair to damage to any platform.	Major repairs of damage are corrective operations involving structural members affecting the structural integrity of a portion or all of the platform. They are subject to the requirements of this subpart, including the industry standards in § 250.901
(4) Make an emergency repair to a primary structural element to restore an existing permitted condition.	Under emergency conditions, you may make repairs to primary structural elements to restore an existing permitted condition without an application or prior approval. You must notify the Regional Supervisor of the damage that occurred within 24 hours, and you must notify the Regional Supervisor of the repairs that were made within 24 hours of completing the repairs
(5) Conversion of the use of an existing mobile offshore drilling unit (MODU).	The Regional Supervisor will determine on a case-by-case basis the requirements for an application for conversion of an existing MODU. Your application must include: (i) The converted MODU's intended location and use; (ii) A demonstration of the adequacy of the design and structural condition of the converted MODU; and (iii) A demonstration that the level of safety for the converted MODU is at least equal to that of reused platforms.

(b) You must design, fabricate, install, inspect, and maintain all new fixed or bottom-founded platforms (e.g., template type, tower type, caisson, gravity-base type, artificial island, etc.) according to all the requirements of this section, § 250.901 (including applicable referenced documents), § 250.902, and §§ 250.913 through 250.918.

(c) Section 250.903 fully describes the facilities that are subject to the Platform Verification Program. In brief, all floating platforms are subject to the Platform Verification Program. Also, all fixed or bottom-founded platforms that meet certain conditions listed in § 250.903(a) are subject to the Platform Verification Program.

§ 250.901 What industry standards must fixed and floating platforms meet?

(a) In addition to the other requirements of this subpart, your plans for fixed or floating platform design, analysis, fabrication, and installation must, as appropriate, conform to:

(1) American Concrete Institute (ACI) Standard 318, Building Code Requirements for Reinforced Concrete, plus Commentary.

(2) ACI 357R, Guide for the Design and Construction of Fixed Offshore Concrete Structures;

(3) American Institute of Steel Construction (AISC) Standard Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design;

(4) American Petroleum Institute (API) Recommended Practice (RP) 2A, Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms;

(5) API RP 2FPS, Recommended Practice for Planning, Designing, and Constructing Floating Production Systems;

(6) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs);

(7) API RP 2SK, Recommended Practice for Design and Analysis of Station Keeping Systems for Floating Structures;

(8) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring;

(9) API RP 2T, Recommended Practice for Planning, Designing and Constructing Tension Leg Platforms;

(10) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities;

(11) American Society for Testing and Materials (ASTM) Standard C 33–99a, Standard Specification for Concrete Aggregates;

(12) ASTM Standard C 94/C 94M–99, Standard Specification for Ready-Mixed Concrete;

(13) ASTM Standard C 150–99, Standard Specification for Portland Cement;

(14) ASTM Standard C 330–99, Standard Specification for Lightweight Aggregates for Structural Concrete;

(15) ASTM Standard C 595–98, Standard Specification for Blended Hydraulic Cements;

(16) AWS D1.1, Structural Welding Code—Steel;

(17) AWS D1.4, Structural Welding Code—Reinforcing Steel;

(18) AWS D3.6M, Specification for Underwater Welding;

(19) NACE Standard MR0175, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment; and

(20) NACE Standard RP 01–76–94, Standard Recommended Practice, Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production.

(b) You must follow the requirements contained in the documents listed under paragraph (a) of this section insofar as they do not conflict with other provisions of 30 CFR part 250. You may use applicable provisions of these documents, as approved by the Regional Supervisor, for the design, fabrication, and installation of platforms such as spars, since standards specifically written for such structures do not exist. You may also use alternative codes, rules, or standards, as approved by the Regional Supervisor, under the conditions enumerated in § 250.141, paragraphs (a), (b), and (c) of this part.

(c) For information on all standards mentioned in this section, see § 250.198 of this part.

§ 250.902 What must an application to approve a fixed or floating platform contain?

You must submit to the Regional Supervisor for approval all applications under this subpart and all significant changes or modifications to approved applications. Your application for all new fixed or floating platforms or major modifications must contain all of the following general facility information:

Required documents	Required contents	Other requirements
(a) Application cover letter	Proposed facility designation, lease number, area, name, and block number, and the type of facility (e.g., drilling, production, quarters)..	You must submit three copies.*
(b) Location plat	Latitude and longitude coordinates, Universal Mercator grid-system coordinates, state plane coordinates in the Lambert or Transverse Mercator Projection System, and distances in feet from nearest block lines.	Your plat must be drawn to a scale of 1 inch equals 2,000 feet and include the coordinates of the the lease block boundary lines. You must submit three copies.*
(c) Front, Side, and Plan View drawings.	Platform dimensions and orientation, elevations relative to M.S.L., and pile sizes and penetrations.	Your drawing sizes must not exceed 11″ x 17″. You must submit three copies.*
(d) Complete set structural drawings	....	Your drawing sizes must not exceed 11″ x 17″. You must submit one copy.
(e) Summary of environmental data	A Summary of the environmental data described in the standards referenced under § 250.901(a) and in § 250.198 of this part, where the data is used in the design or analysis of the platform. Examples of relevant data include information on waves, wind, current, tides, temperature, snow and ice effects, marine growth, and water depth.	You must submit one copy.
(f) Summary of the enigneering design data.	Loading information (e.g., live, dead, environmental), structural information (e.g., design-life, material types, cathodic protection systems, design criteria fatigue life, fabrication and installation guidelines), and foundation information (e.g., soil stability, design criteria).	You must submit one copy.

Required documents	Required contents	Other requirements
(g) Project-specific	All studies pertinent to platform design or installation, e.g., soil and/or oceanographic reports.	You must submit one copy each study.
(h) Description of the loads imposed on the facility.	Loads imposed by production and pipeline risers and mooring and anchoring systems.	You must submit one copy.
(i) A copy of the inservice inspection plan.	This plan is described in §250.916	You must submit one copy.
(j) Certification	The following statement: ''The design of this structure has been certified by a recognized classification society, or a registered civil or structural engineer, or equivalent, specializing in the design of offshore structures. The certified design and as-built plans and specifications will be on file at (give location)''.	An authorized company must sign the registered statement. You must submit one copy.

*For your facilities subject to Platform Verification Program requirements in §§ 250.903 through 250.912, you must submit one additional copy of these items (four copies total).

§ 250.903 Which of my platforms, associated structures, and major modifications are subject to the Platform Verification Program?

(a) All new fixed or bottom-founded platforms that meet any of the following five conditions are subject to the Platform Verification Program:

(1) Platforms installed in water depths exceeding 400 feet (122 meters);

(2) Platforms having natural periods in excess of 3 seconds;

(3) Platforms installed in areas of unstable bottom conditions;

(4) Platforms having configurations and designs which have not previously been used or proven for use in the area; or

(5) Platforms installed in seismically active areas.

(b) All new floating platforms are subject to the Platform Verification Program. Floating platforms include floating production systems (FPSs) such as column-stabilized units (CSUs); floating production, storage and offloading systems (FPSOs); tension-leg platforms (TLPs); spars, etc. The following structures that may be associated with a floating platform are also subject to the Platform Verification Program:

(1) Drilling and production risers, and riser tensioning systems;

(2) Turrets and turret-and-hull interfaces;

(3) Foundations and anchoring systems; and

(4) Mooring or tethering systems.

(c) Platform Verification Program requirements apply to any major modification to a fixed or floating platform covered under this section.

(d) The applicability of Platform Verification Program requirements to other types of facilities will be determined by MMS on a case-by-case basis.

§ 250.904 If my platform, associated structure, or major modification is subject to the Platform Verification Program, what must I do?

If your platform, associated structure, or major modification meets the criteria in § 250.903, you must:

(a) Design, fabricate, and install your facility, associated structures, or major modification to your facility according to the requirements of §§ 250.900 through 250.918, and the applicable documents listed in § 250.901(a);

(b) Submit for the Regional Supervisor's approval three copies each of the design verification, fabrication verification, and installation verification plans required by § 250.905; and

(c) Include as a part of each verification plan required by § 250.905 your nomination of a Certified Verification Agent (CVA);

(d) Follow the additional requirements in §§ 250.906 through 250.912; and

(e) Prepare and submit for MMS review, plans for ship-shaped FPSs which are modified to address in detail only those items listed in § 250.903(b). For detailed requirements pertaining to the ship-shaped hull and superstructure, you must refer to, and comply with applicable U.S. Coast Guard regulations.

§ 250.905 What plans must I submit under the Platform Verification Program?

If your platform, associated structure, or major modification meets the criteria in § 250.903, you must submit all of the following plans required by this section:

(a) *Design verification plan.* You may submit your design verification plan with or subsequent to the submittal of your Exploration Plan (EP) or Development and Production Plan (DPP). You may not submit your design verification plan before you submit your EP or DPP. Your design verification must be conducted by, or be under the direct supervision of, a registered professional civil or structural engineer or equivalent, with previous experience in directing the design of similar facilities, systems, structures, or equipment. Your design verification plan must include the following:

(1) All design documentation specified in § 250.902;

(2) Abstracts of the computer programs used in the design process; and

(3) A summary of the major design considerations and the approach to be used to verify the validity of these design considerations.

(b) *Fabrication verification plan.* You must submit your fabrication verification plan to the Regional Supervisor, and the Regional Supervisor must approve your fabrication verification plan before you may initiate any related operations. Your fabrication verification plan must include the following:

(1) Fabrication drawings and material specifications for artificial island structures and major members of concrete- and steel-gravity structures;

(2) For jacket and floating structures, all the primary load-bearing members included in the space-frame analysis; and

(3) A summary description of the following:

(i) Structural tolerances;

(ii) Welding procedures;

(iii) Material (concrete, gravel, or silt) placement methods;

(iv) Fabrication standards;

(v) Material quality-control procedures;

(vi) Methods and extent of nondestructive examinations for welds and materials; and

(vii) Quality assurance procedures.

(c) *Installation verification plan.* You must submit your installation verification plan to the Regional Supervisor, and the Regional Supervisor must approve your installation verification plan before you may initiate any related operations. Your installation verification plan must include:

(1) A summary description of the planned marine operations;

(2) Contingencies considered;

(3) Alternative courses of action; and

(4) The inspections to be performed, including an identification of areas to be inspected and the acceptance and rejection criteria to be used.

§ 250.906 When must I resubmit Platform Verification Program plans?

(a) You must resubmit any design verification, fabrication verification, or installation verification plan to the Regional Supervisor for approval if:

(1) The CVA changes;

(2) The CVA's or assigned personnel's qualifications change; or

(3) The level of work to be performed changes.

(b) If only part of a verification plan is affected by one of the changes described in paragraph (a) of this section, you can resubmit only the affected part. You do not have to resubmit the summary of technical details unless you make changes in the technical details.

§ 250.907 When must I combine Platform Verification Program plans?

You must combine fabrication verification and installation verification plans for manmade islands or platforms fabricated and installed in place.

§ 250.908 How do I nominate a CVA?

(a) As part of your design verification, fabrication verification, or installation verification plan, you must nominate a CVA for the Regional Supervisor's approval. You must specify whether the nomination is for the design, fabrication, or installation phase of verification; for two phases; or for all three phases.

(b) For each CVA, you must submit a qualification statement that includes the following:

(1) Previous experience in third-party verification or experience in the design, fabrication, or installation of fixed offshore oil and gas platforms, similar facilities and other structures, floating platforms, manmade islands, other marine structures, and related systems and equipment;

(2) Technical capabilities of the individual or the primary staff to be associated with the CVA functions for the specific project;

(3) Size and type of organization or corporation;

(4) In-house availability of, or access to, appropriate technology, i.e., computer programs and hardware and testing materials and equipment;

(5) Ability to perform the CVA functions for the specific project considering current commitments;

(6) Previous experience with MMS requirements and procedures;

(7) The level of work to be performed by the CVA; and

(8) A list of documents to be furnished to the CVA.

§ 250.909 What are the CVA's primary responsibilities?

(a) The CVA nominated by you and approved by the Regional Supervisor must conduct specified reviews according to §§ 250.910, 250.911, and 250.912.

(b) The CVA must handle all data you provide in the strictest confidence. Other than to MMS, the CVA must not release any data without your consent.

(c) Individuals or organizations acting as CVAs for a particular platform or floating facility must not function in any capacity other than that of a CVA for that specific project whenever the additional activities would create a conflict of interest, or the appearance of a conflict of interest.

§ 250.910 What are the CVA's primary duties during the design phase?

(a) The CVA must conduct the design verification to ensure that the proposed fixed or floating platform or major modification is designed to withstand the maximum environmental and functional load conditions anticipated during the intended service life at the proposed location.

(b) The CVA must consider the applicable provisions of the documents listed in § 250.901(a) and of §§ 250.913 through 250.915 and use good engineering practice in conducting an independent assessment of the adequacy of all proposed:

(1) Planning criteria;

(2) Operational requirements;

(3) Environmental data;

(4) Load determinations;

(5) Stress analyses;

(6) Material designations;

(7) Soil and foundation conditions;

(8) Safety factors; and

(9) Other pertinent parameters of the proposed design.

(c) The CVA must submit interim reports to the Regional Supervisor and to you, as appropriate.

(d) The CVA, upon completion of the design verification, must prepare a final report which summarizes the material reviewed and the CVA's findings. The CVA must submit one copy of the report to the Regional Supervisor. The CVA must make this submittal within 6 weeks of the receipt of the design data or from the date the approval to act as a CVA was issued, whichever is later. The final report must include:

(1) The CVA's recommendation that the Regional Supervisor either accept, request modifications, or reject the proposed design;

(2) The particulars of how, by whom, and when the independent review was conducted; and

(3) Any special comments the CVA may deem necessary.

§ 250.911 What are the CVA's primary duties during the fabrication phase?

(a) The CVA must monitor the fabrication of the fixed or floating platform or major modification to ensure that it has been built according to the approved design plans and specifications and the fabrication plan.

(b) The CVA must make periodic onsite inspections while fabrication is in progress. The CVA must verify the following fabrication items, as appropriate:

(1) Quality control by lessee and builder;

(2) Fabrication site facilities;

(3) Material quality and identification methods;

(4) Fabrication procedures specified in the approved plan and adherence to such procedures;

(5) Welder and welding procedure qualification and identification;

(6) Structural tolerences specified and adherence to those tolerances;

(7) The nondestructive examination requirements and evaluation results of the specified examinations;

(8) Destructive testing requirements and results;

(9) Repair procedures;

(10) Installation of corrosion-protection systems and splash-zone protection;

(11) Erection procedures to ensure that overstressing of structural members does not occur;

(12) Alignment procedures;

(13) Dimensional check of the overall structure, including any turrets, turret and hull interfaces, any mooring line and chain and riser tensioner line segments; and

(14) Status of quality-control records at various stages of fabrication.

(c) The CVA must consider the applicable provisions of the documents listed in § 250.901(a) and of §§ 250.913 through 250.915 and use good engineering practice in conducting the independent assessment of the adequacy of the fabrication of the fixed or floating platform or major modification.

(d) The CVA must submit interim reports to the Regional Supervisor and to you, as appropriate.

(e) If the CVA finds that fabrication procedures are changed or design specifications are modified, the CVA must inform you. If you accept the modifications, then the CVA must so inform the Regional Supervisor.

(f) The CVA must prepare a final report covering the adequacy of the entire fabrication phase. The CVA is not required in the final report to cover aspects of the fabrication already included in interim reports. The CVA must submit one copy of the report to the Regional Supervisor immediately after completion of the fabrication of the fixed or floating platform. In the report the CVA must:

(1) Give details of how, by whom, and when the independent monitoring activities were conducted;

(2) Provide any special comments that the CVA deems necessary;

(3) Describe the CVA's activities during the verification process;

(4) Summarize the CVA's findings

(5) Confirm or deny compliance with the design specifications and the approved fabrication plan; and

(6) Make a recommendation to accept or reject the fabrication.

§ 250.912 What are the CVA's primary duties during the installation phase?

(a) The CVA must perform the following:

(1) Witness the loadout of the jacket, decks, piles, or structures from each fabrication site;

(2) Review the towing records;

(3) Witness the loadout of a floating platform;

(4) Conduct an onsite survey after transportation to the approved location;

(5) Witness the actual installation of the fixed or floating platform or major modification;

(6) For floating platforms, witness the installation of the mooring, tethering, and anchoring systems; and

(7) Determine that the platform has been installed at the approved location according to the approved design and the installation plan.

(b) The CVA must consider the applicable provisions of the documents listed in § 250.901(a) and of §§ 250.913 through 250.915 and use good engineering practice in conducting an independent assessment of the adequacy of the installation activities. The CVA must verify the following parts of the overall installation process, as appropriate:

(1) Loadout and initial flotation operations, if any;

(2) Towing operations to the specified location;

(3) Launching and uprighting operations;

(4) Submergence operations;

(5) Pile or anchor installation;

(6) Installation of mooring and tethering systems; and

(7) Final deck and component installations on fixed and floating offshore facilities.

(c) The CVA must observe the installation activities, spot-check equipment, procedures, and recordkeeping, as necessary, to determine compliance with the applicable documents listed in § 250.901(a) and of §§ 250.913 through 250.915 and the approved plans, and immediately report to you and the Regional Supervisor any discrepancies or damage to structural members. You must obtain approval for modified installation procedures or for major deviations from approved installation procedures from the Regional Supervisor.

(d) The CVA must submit interim reports to you and the Regional Supervisor, as appropriate.

(e) The CVA must prepare a final report covering the adequacy of the entire installation phase and submit one copy of the final report to the Regional Supervisor within 2 weeks of completion of the installation of the platform. In the report, the CVA must:

(1) Give details of how, by whom, and when the independent monitoring activities were conducted;

(2) Provide any special comments that the CVA deems necessary;

(3) Describe the CVA's activities during the verification process;

(4) Summarize the CVA's findings;

(5) Write a confirmation or denial of compliance with the approved installation plan; and

(6) Provide recommendation to accept or reject the installation.

§ 250.913 What are the minimum structural fatigue requirements?

There are numerous circumstances in which it may be necessary to conduct a detailed analysis of cumulative fatigue damage on structural members and joints. The following table provides minimal requirements for structural members and joints which require a detailed analysis of cumulative fatigue damage.

If * * *	Then * * *
(a) There is sufficient structural redundancy to prevent catastrophic failure of the member or join under consideration.	The results of the analysis must indicate a minimum calculated life of twice the design life of the platform.
(b) There is not sufficient structural reduncancy to prevent catastrophic failure of the member or joint.	The results of a fatigue analysis must indicate a minimum calculated life of three times the design life of the platform.
(c) The desirable degree of redundancy is significantly reduced as a result of fatigue damage.	The results of a fatigue analysis must indicate a minimum calculated life of three times the design life of the platform.

§ 250.914 What records must I keep for all primary structural members?

You must record and retain the origin and relevant material test results of all primary structural materials during all stages of construction. Primary material is material that, should it fail, it would lead to a significant reduction in platform safety, structural reliability, or operating capabilities. Items such as steel brackets, deck stiffeners and secondary braces or beams would not generally be considered primary structural members (or materials).

§ 250.915 Where must I locate foundation boreholes?

(a) For fixed or bottom-founded platforms and tension leg platforms, your maximum distance from any foundation pile to a soil boring must not exceed 500 feet.

(b) For deepwater floating platforms which utilize catenary or taut-leg moorings, you must take borings at the most heavily loaded anchor location, at the anchor points approximately 120 and 240 degrees around the anchor pattern from that boring, and, as necessary, other points throughout the anchor pattern to establish the soil profile suitable for foundation design purposes.

§ 250.916 What in-service inspection requirements must I meet?

(a) You must develop an in-service inspection plan. As a minimum, your plan must fulfill the recommendations of the appropriate API documents listed in § 250.901(a). Your plan must specify the type, extent, and frequency of in-place inspections which your contractor will conduct for both the above water and the under water structure of all platforms, and pertinent components of the mooring systems for floating platforms.

(b) You must submit a report annually on November 1 to the Regional Supervisor that must include :

(1) A list of fixed or floating platforms inspected in the preceding 12 months;

(2) The extent and area of inspection;

(3) The type of inspection employed, i.e., visual, magnetic particle, ultrasonic testing; and

(4) A summary of the testing results indicating what repairs, if any, were needed and the overall structural condition of the fixed or floating platform.

§ 250.917 What are the requirements for fixed or floating platform removal and location clearance?

You must remove all structures according to §§ 250.1725 through 250.1730 of Subpart Q—Decommissioning Activities—of this part.

§ 250.918 What records must I keep?

You must compile, retain, and make available to MMS representatives for the functional life of all fixed or floating platforms:

(a) The as-built drawings;

(b) The design assumptions and analyses;

(c) A summary of the fabrication and installation nondestructive examination records; and

(d) The inspection results from the inspections required by § 250.916.

8. In § 250.1002 paragraphs (b)(4) and (b)(5) are added to read as follows:

§ 250.1002 Design requirements for DOI pipelines.

* * * * *

(b) * * *

(4) If you are installing pipelines constructed of unbonded flexible pipe, they must be built according to the standards and the third-party review standards for an independent verification agent (IVA) in API Spec 17J.

(5) You must construct pipeline risers for tension leg platforms and other floating platforms according to the design standards of API RP 2RD.

* * * * *

9. In § 250.1007, a new sentence is added at the end of paragraph (a)(4) to read as follows:

§ 250.1007 What to include in applications.

(a) * * *

(4) * * * If your application involves using unbonded flexible pipe, you must include a review by a third-party IVA according to API Spec 17J.

* * * * *

[FR Doc. 01–31723 Filed 12–26–01; 8:45 am]

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DEPARTMENT OF TRANSPORTATION

Coast Guard

33 CFR Part 117

[CGD09–01–148]

RIN–2115–AE47

Drawbridge Operation Regulations; Chicago River, IL

AGENCY: Coast Guard, DOT.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Coast Guard proposes to revise the operating regulation governing drawbridges over Chicago River waterways. The proposed rule would add Division Street bridge, mile 3.30, over the North Branch of Chicago River, to the current list of bridges not required to open for navigation; remove the requirement for Kinzie Street bridge, mile 1.81 over North Branch of Chicago River, and Cermak Road bridge, mile 4.05 over South Branch of Chicago River, to open on signal for commercial vessels due to the recently accomplished increases in vertical clearances; require a 12-hour advance notice requirement from commercial vessels year-round for City of Chicago moveable bridges; update ownership of certain railroad bridges; specify rush hour times (7 a.m. to 10 a.m. and 4 p.m. to 6:30 p.m.—Monday through Friday, with the exception of Federal holidays) that City of Chicago bridges would not be required to open for any vessels; and generally make the regulation easier to read and understand.

DATES: Comments must be received on or before February 25, 2002.

ADDRESSES: Comments may be mailed or delivered to: Commander (obr), Ninth Coast Guard District, 1240 East Ninth Street, Room 2019, Cleveland, OH, 44199–2060 between 8 a.m. and 3 p.m., Monday through Friday, except Federal holidays. The telephone number is (216) 902–6084.

FOR FURTHER INFORMATION CONTACT: Mr. Scot M. Striffler, Project Manager, Ninth Coast Guard District Bridge Branch, at (216) 902–6084.

SUPPLEMENTARY INFORMATION:

Request for Comments

The Coast Guard encourages interested persons to participate in this rulemaking by submitting written data, views or arguments for or against this rule. Persons submitting comments should include names and addresses, identify the rulemaking [CGD09–01–148] and the specific section of this proposal to which each comment applies, and give the reason(s) for each comment. Please submit all comments and attachments in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. Persons wanting acknowledgement of receipt of comments should enclose a stamped, self-addressed postcard or envelope.

The Coast Guard plans no public hearing. Individuals may request a public hearing by writing to the address under **ADDRESSES.** The request should include the reasons why a hearing would be beneficial. If the Coast Guard determines that the opportunity for oral presentation will aid this rulemaking, we will hold a public hearing at a time and place announced by a subsequent notice in the **Federal Register**.

Background and Purpose

The City of Chicago has requested that Commander, Ninth Coast Guard District, revise the operating regulations for Chicago City operated drawbridges over Chicago River waterways. The primary changes are: (1) Remove the requirements for Kinzie Street bridge over the North Branch and Cermak Road bridge over the South Branch to open on signal for commercial vessels due to restrictive clearances. Both bridges have been raised to provide vertical clearances consistent with other fixed and moveable bridges on the Chicago River system. (2) Add Division Street bridge over the North Branch of Chicago River to the current list of drawbridges not required to open for vessels. (3) Require a 12-hour advance notice requirement for bridge openings from commercial vessels for City of Chicago moveable bridges throughout the year. (4) Clarify rush hour times (7 a.m. to 10 a.m. and 4 p.m. to 6:30 p.m.—Monday through Friday, with the exception of Federal holidays) that City of Chicago bridges would not be required to open for any vessels.

Discussion of Proposed Rule

The current operating regulations for Chicago River bridges are contained in 33 CFR 117.391. This section was last changed on October 6, 1995 (60 FR 52311) to establish opening schedules for recreational vessels. This proposed rule only alters the sections pertaining to recreational vessels by specifying rush hour times (7 a.m. to 10 a.m. and 4 p.m. to 6:30 p.m.—Monday through Friday, with the exception of Federal holidays) that bridges would not be required to open.

The City of Chicago requested that both Kinzie Street bridge over North Branch and Cermak Road bridge over South Branch be granted the same status as all other City of Chicago bridges and