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

DEPARTMENT OF THE INTERIOR

Minerals Management Service

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RIN 1010–AC85

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

AGENCY: Minerals Management Service (MMS), Interior.

ACTION: Final rule.

SUMMARY: This rule amends our regulations concerning platforms and structures to include coverage of floating offshore oil and gas production platforms. The rule also incorporates into MMS regulations a body of industry standards pertaining to floating production systems (FPSs). Limited changes are also made to regulations concerning oil and gas production safety systems; and pipelines and pipeline rights-of-way. These changes are needed because of the rapid increase in deepwater exploration and development, and industry's increasing reliance on floating facilities for those activities. Incorporating the industry standards into MMS regulations will save the public the costs of developing separate, and possibly duplicative, government standards, and will streamline our procedures for reviewing and approving new offshore floating platforms.

DATES: This rule becomes effective on August 18, 2005. The incorporation by reference of the publications listed in the regulation is approved by the Director of the Federal Register as of August 18, 2005.

FOR FURTHER INFORMATION CONTACT: Tommy Laurendine, Chief, Office of Structural and Technical Support (OSTS) at (504) 736–5709 or FAX (504) 736–1747.

SUPPLEMENTARY INFORMATION:

Background

In response to the rapid increase in deepwater oil and gas exploration and development, on December 27, 2001, MMS published a proposed rule (66 FR 66851–66865) to amend subpart I of 30 CFR part 250—Platforms and Structures. The proposed rule was designed to streamline the permitting process for floating platforms, and to incorporate by reference into MMS regulations industry standards addressing various aspects of FPSs.

The remarkable increase in oil and gas exploration, development, and production in deepwater is due to the development of new technologies that (1) enable drilling and production in deeper waters; and (2) reduce operational costs and risks. In 1993, deepwater areas of the OCS (water depths greater than 1,000 feet, or 305 meters) accounted for approximately 12 percent of the oil and 2 percent of the gas of total offshore production. Discovery and development of deepwater fields began accelerating in 1994. By the end of 2004, deepwater areas accounted for about 62 percent of the oil and 32 percent of the gas of total offshore production.

The productivity of the new deepwater wells is enormous compared to past wells in more shallow waters. Historically, offshore wells generally have produced between 200 and 300 barrels (bbls) of oil per day. However, some deepwater wells have produced at rates over 30,000 bbls per day. Success in deepwater is evident in both the high production rates and sustained drilling for new discoveries announced each year. Exploratory drilling has moved into water depths of over 10,000 feet (3,048 meters).

By 2003, 27 permanent development platforms had been approved for installation in waters over 1,000 feet deep (305 meters). Of these, 16 structures are floating platforms and 11 are fixed. All of these production platforms were approved on a case-by-case basis under existing regulations. However, it will streamline the permitting process for MMS to have 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, station-keeping and mooring systems, flexible pipelines, and hazards analysis.

Use of Industry Standards

Under existing regulations, lessees and operators must 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 already incorporated in the regulations, they have the option to use equivalent standards, provided they first obtain our approval.

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" to eliminate "unnecessary duplication and complexity" in developing 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 they determine that the use of consensus standards would be inconsistent with applicable law or otherwise impractical.

The Purpose of This Rule

The purpose of this rule is to incorporate into MMS regulations a body of industry standards that will enable MMS to more efficiently examine plans and issue permits for floating offshore platforms. Until this rulemaking, MMS regulations have not specifically addressed these facilities separately from fixed platforms. Therefore, this rule includes a complete rewrite of subpart I of 30 CFR part 250 to address floating platforms. This rule also modifies select sections of subpart J concerning the incorporation of American Petroleum Institute (API) Spec 17J and its use when installing pipelines constructed of unbonded flexible pipe. Select sections of subpart H are modified to reference API Recommended Practice (RP) 14J as well as API Spec 17J. Incorporating the voluntary industry standards will save the public the cost of developing government-specific standards.

This rule will 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 OCS in two ways. First, it will provide more certainty to the lessees' design engineers so that they will know in advance what design criteria are acceptable to MMS. Second, it will enhance MMS engineers' abilities to review each new project to ensure structural integrity, operational and human safety, and environmental protection. The rule will establish a single body of standards on which each new project can be based, and result in streamlining the regulatory review process.

Incorporating the industry standards into MMS regulations will dictate that respondents comply with the requirements in the incorporated documents. This includes certified verification agent (CVA) reviews and hazards analyses. This will 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)). 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 this rule.

With this final rule, MMS will incorporate seven API standards, and one American Welding Society (AWS) standard. MMS has actively participated in developing several of these standards, and believes that it would be difficult for the agency to write government regulations that would be either as technically detailed or as broad in scope as the standards. Incorporating these standards will help reduce the size and complexity of subpart I. Moreover, writing government regulations embodying these standards would be time-consuming and not economically efficient. Nor could it be done with the same level of expertise that was involved in the industry effort. MMS believes that it is entirely within the letter and spirit of the NTTAA that these voluntary industry standards be incorporated into our regulations. It is in the public interest that MMS adopt these standards.

The eight industry standards to be incorporated are as follows:

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

(2) *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 Order No. G02SK2*. This standard addresses station-keeping systems for floating platforms. These systems are not explicitly covered under current regulations.

(3) *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 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 deepwater areas. 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 heavily on the analysis contained in API RP 2A, which is already incorporated into MMS regulations, 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.

(4) *API RP 2FPS, Recommended Practice for Planning, Designing, and Constructing Floating Production Systems, First Edition, March 2001, API Order No. G2FPS1*. API 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.

(5) *API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, First Edition, September 1, 1993, API Order No. 811–07200*. Implementing this standard for all new deepwater floating production platforms will be the most costly element of this rule for industry. During 2000, a consensus was reached within the industry that the complexities and safety issues involved in FPSs warrant the application 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 bbls per day. Therefore, MMS has 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, MMS believes 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.) MMS will require an analysis of operational hazards to be included as an integral part 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 Order No. G17J02*. For several years MMS has been permitting remote subsea wells that use flexible pipe for deep sea production pipelines. API Spec 17J serves the interests of environmental protection and safety by providing guidance to both regulators and industry on the proper design and construction of flexible pipelines and flowlines. The industry projects that up to 50 percent of future deepwater wells will be remote subsea wells tied back to existing production platforms. There will also be an increasing number of shallow water subsea tie-backs. Therefore, this standard will be essential for future production operations.

(7) *American Welding Society, AWS D3.6M:1999, Specification for Underwater Welding (AWS D3.6M)*. MMS refers to this document every time we receive an application for an underwater welding repair. This document is analogous and complementary 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 current MMS regulations for over 20 years. Further, MMS was a member of the subcommittee which developed AWS D3.6M. Underwater welding is used infrequently because of the expense 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. MMS presently receives applications for underwater welding repairs on an infrequent basis, and AWS D3.6M is the primary document the industry follows for these purposes. This standard needs to be incorporated into our regulations because MMS anticipates 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 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 seen only limited use in the mooring systems of floating OCS platforms. Given the lack of long-term experience with the use of synthetic fiber rope, API RP 2SM will serve as the primary reference document 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

This final rule totally reorganizes subpart I. Much of this reorganization is a result of MMS'' incorporation of the 21st edition of API RP 2A WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design; Twenty-First Edition, December 2000. This document was incorporated into MMS regulations, under separate rulemaking, on April 21, 2003. The incorporation allowed the elimination of much of the verbiage in the current subpart I regulations. Subpart I was further reorganized for clarity in this final rule.

In addition to incorporating new industry documents, the revised subpart I adds 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 was published in the **Federal Register** on January 15, 1999 (64 FR 2660). The MOU describes our respective and overlapping responsibilities for regulating oil and gas activities on the OCS.

Discussion and Analysis of Comments

Since the MMS first proposed this rule in December 2001, the location and numbering of many of the proposed regulatory sections has changed. In some cases, the changes were made to provide a more logical progression of the approval process. In other instances, proposed regulatory sections were moved and renumbered in this final rule to accommodate industry commentors' suggestions and additions to the proposed rules. The following table shows the final rule section numbers and the original proposed sections:

Final section of 30 CFR	Proposed section of 30 CFR
§ 250.105	§ 250.105
§ 250.198	§ 250.198
§ 250.199	New content not in proposed rule.
Proposed wording deleted from final rule.	§ 250.204
§ 250.800	§ 250.800
§ 250.803	§ 250.803
§ 250.900	§ 250.900
§ 250.901	§ 250.901
§ 250.902	§ 250.917
§ 250.903	§ 250.914
§ 250.904	New content not in proposed rule.
§ 250.905	§ 250.902
§ 250.906	These requirements are not in the proposed rule. Requirements are from superseded regulations at § 250.909.
§ 250.907	§ 250.915
§ 250.908	§ 250.913
§ 250.909	New content not in proposed rule.
§ 250.910	§ 250.903
§ 250.911	§ 250.904
§ 250.912	§ 250.905 and § 250.907
§ 250.913	§ 250.906
§ 250.914	§ 250.908
§ 250.915	§ 250.909
§ 250.916	§ 250.910
§ 250.917	§ 250.911
§ 250.918	§ 250.912
§ 250.919	§ 250.916
§ 250.920	New content not in proposed rule.
§ 250.921	§ 250.913; new content not in proposed rule.
§ 250.1002	§ 250.1002
§ 250.1007	§ 250.1007

Eight organizations submitted nine comments on the proposed rulemaking. Respondents included the American Bureau of Shipping (ABS); the Offshore Operator's Committee (OOC); Shell Exploration & Production Company (Shell), which commented twice; the Independent Petroleum Association of America (IPAA); the National Ocean Industries Association (NOIA); ChevronTexaco; Newfield Exploration Company (Newfield); and ATP Oil & Gas Corporation (ATP). These respondents raised a number of complex issues that are discussed immediately below.

Issue No. 1: Subpart I Should Be Broken Down To Separately Address Fixed and Floating Platforms

ChevronTexaco commented as follows:

> There are significant differences between the two field development concepts covered by the proposed rewrite of Subpart I: The fixed production platform and the floating production platform. These differences include such things as number of deployments of each concept (a handful of floating production platforms versus thousands of shallow and deepwater fixed platforms); design, fabrication, and installation complexity; availability of design firms and CVA firms; and cost. ChevronTexaco suggests that forcing one Subpart to cover both concepts is extremely confusing, lacks focus on the unique characteristics of the individual concepts, and creates a document that is difficult to read. ChevronTexaco recommends two distinctly separate sections of CFR 250, either within Subpart I, or preferably in a new Subpart covering floating production platforms. Ultimately, ChevronTexaco feels

this will provide for a clearer document by removing the ambiguities created by attempting to use wording originally written for fixed platform in rules for floating platforms.

More specifically, OOC commented concerning proposed § 250.902 (§ 250.905 in the final rule):

* * * The proposed regulations seems [sic] to assume that the design stages of a floating platform matches that for a fixed platform. For a fixed platform, in many cases the platform is fully designed and is then fabricated. For a floating platform, the design may be done in stages with fabrication commencing on various systems prior to the final design of other systems. This rule making does not seem to take this into account. We suggest that MMS investigate project sequencing and take that into account in the rulemaking.

NOIA, Shell, and Newfield all provided similar comments on this question.

The Platform Verification Program (PVP) described in this final rule at §§ 250.909—250.918 (§§ 250.903—250.912 in the proposed rule) covers all new floating production platforms and fixed platforms meeting one or more of five very specific criteria: (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. The final rule language was changed to highlight the differences between the requirements for fixed and floating structures, but MMS concluded that separate subparts were not necessary.

MMS agrees that the third-party justification procedures for fixed versus floating platforms can differ significantly based on certification procedures (*e.g.,* use of a CVA versus a classification society) and the regulatory agencies involved (*e.g.,* primarily MMS for a fixed platform, versus both MMS and USCG for a floating platform). The regulatory language for certification under the PVP is written broadly so that it can cover both fixed and floating platforms.

The specific path to obtain approval for a particular platform will be based on the structural components and environmental conditions peculiar to that platform. It is quite conceivable that a floating platform will undergo more complicated design, CVA, and approval processes than a fixed platform. After evaluating the comments, MMS concluded that it is better to allow engineering staffs to use their judgment in obtaining the various approvals than to try to write a ''cookbook'' regulation on the step-by-step certification or classification process for the design, fabrication, and installation of a hypothetical platform.

New innovations in offshore platforms are constantly emerging, and it would be impractical, if not impossible, to cover all the permutations in design or construction that could eventually evolve. The fact that most of the deepwater facilities MMS has permitted are floating facilities provides convincing evidence in favor of staying flexible in adapting our regulations to various types of facilities.

Some commentors believe it would be more confusing to separate subpart I into ''fixed'' and ''floating'' components, because of the many systems and technical problems which both types of platforms have in common. MMS agreed, and concluded that it was less satisfactory to have two subsections, because the greater specificity concerning either type of system could encourage more micro-managing in the final regulations. This could lead to less flexibility for innovative designs.

OOC commented concerning proposed § 250.901(a):

* * * In lieu of listing the standards for fixed and floating platforms together, it would be clearer if three lists were given: 1. Fixed only, 2. floating only and 3. fixed and floating. This would eliminate confusion on the applicability of standards such as 14J which only new floating platforms have to meet.

Shell and Newfield provided similar comments.

MMS agreed, and has added a chart to the final regulation to reduce confusion about the applicability of referenced industry standards.

Issue No. 2: The Subpart I Revisions Do Not Follow the MOU Between MMS and USCG

OOC, in commenting on proposed § 250.904(e), now final § 250.911(g), asserted that ''The MOU gives the USCG sole jurisdiction over the structural design of ship-shaped hulls and superstructures.''

MMS disagrees, and believes that this assertion oversimplifies the MOU provisions assigning MMS's and USCG's respective and joint responsibilities for offshore floating platforms. The specific items listed in proposed § 250.903(b), and now in § 250.910(b) of this final rule, include the following structures normally associated with floating platforms: (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. The following paragraphs address these items in their respective order with regard to the MOU between MMS and USCG.

Section III of the MOU contains a table listing the agencies' respective and joint responsibilities associated with mobile offshore drilling units (MODUs) and fixed and floating OCS facilities. The table indicates in Item 2.c that, for all floating facilities, MMS is the lead agency for ''risers (drilling, production, and pipeline)'' and further notes that ''Some pipeline risers may be subject to the Research and Special Programs Administration's (RSPA) jurisdiction'' (64 FR 2662).

Concerning ''turrets and turret-and-hull interfaces,'' Item 2.a of the MOU Section III table states as follows (64 FR 2661):

USCG responsibilities for fabrication, installation, and inspection of floating units are found in 33 CFR Subchapter N. MMS responsibilities are found in 30 CFR Subpart I. USCG and MMS will each review the design of the turret and turret/hull interface structure for ship-shaped floating facilities. All other aspects of the design and fabrication of all ship-shape floating facilities will receive only USCG review. All design, fabrication, and installation activities of all non-ship-shape floating facilities will be reviewed by both agencies.

Thus the MOU clearly shows that MMS and USCG both have responsibility for reviews of the turret and turret/hull interface structure of ship-shaped floating facilities.

Concerning ''foundations and anchoring systems,'' Item 4.a of the MOU Section III table indicates that MMS is the lead agency for foundations for both fixed and floating facilities (64 FR 2662). The MOU was written this way because MMS is the Federal agency with the geotechnical expertise essential for reviewing and evaluating foundation integrity for fixed and floating production platforms.

Closely related to ''foundations and anchoring systems'' are ''mooring or tethering systems.'' Item 4.b of the MOU Section III table indicates that ''mooring and tethering systems'' for floating production facilities are under the joint responsibility of both MMS and USCG. USCG is unquestionably the agency with the expertise and responsibility for determining the safety and integrity of the hull of a ship-shaped FPS. However, the anchoring and mooring system for a ship-shaped FPS is inherently different from the anchoring and mooring system for a ship. The FPS must remain moored on location for many months, if not years, and in such a way that oil and gas production systems will not be adversely affected by excessive movement. For Item 4.b, the MOU states that ''USCG is not responsible for site specific mooring analysis.'' The question of an effective and safe mooring system cannot be considered apart from the question of the sea bottom into which the mooring system is anchored. Again, MMS is the agency with the geotechnical expertise to determine whether the mooring system for a FPS is being anchored into stable sediments.

OOC, commenting on proposed § 250.901(a) stated:

> * * * In the current MOU between MMS and USCG, the agencies have joint jurisdiction over the structural design on non-ship shaped hulls. USCG treats floating production platforms as MODUs. In 46 CFR 108.113, USCG requires each unit to meet the structural standards of the American Bureau of Shipping ''Rules for Building and Classing Offshore Mobile Drilling Units''. There is concern that there could be conflicts between the recommended practices and standards proposed for adoption in this rulemaking and the USCG structural requirements. Industry has not undertaken an exhaustive study to determine if conflicts exist. Further, it is confusing to industry to have joint jurisdiction over the same system, especially when the criteria is [sic] different. It is suggested that MMS and USCG work together and either adopt the same criteria for systems in which they have joint jurisdiction or that one agency clearly be given the lead jurisdiction for each system and move away from the joint jurisdiction where both agencies have to approve a system.

Shell, NOIA, and Newfield expressed similar concerns.

MMS believes that the respondents' concerns about coordination between MMS and USCG are overstated. MMS further believes that the procedures outlined in the new subpart I and the provisions of the MOU between MMS and USCG are sufficient to mitigate industry's concerns of duplicative and conflicting requirements between MMS and USCG. That said, conflicts cannot be entirely avoided. In the responsibilities section of the current MOU, three general classifications of facilities are identified (i.e., MODU, fixed facility, and floating facility). The lead agency for each system and sub-system is also identified.

Since USCG reviews the general marine requirements for floating facilities from a ship perspective, and MMS reviews oil and gas operations on this facility from a platform perspective, it is not always possible to adopt the same criteria. However, the MOU requires the identified lead agency to coordinate with the other agency, as appropriate, and also requires that both agencies work together to develop necessary standards and to minimize duplicative and conflicting requirements whenever there are overlapping responsibilities. MMS does not believe that anything in this final rulemaking will prevent this coordination from continuing.

Issue No. 3: There Could Be Conflicts Between the MMS Platform Verification Program and the USCG Subchapter N Requirements for Floating Facilities

OOC commented as follows in its cover letter:

> * * * In the current Memorandum of Understanding (MOU) between MMS and USCG, both agencies have joint jurisdiction and responsibility to review and approve the structural design of non ship shaped floating platforms. Prior to this rulemaking, MMS did not have regulations expressly covering floating platforms; therefore, floating platforms have been designed in accordance with USCG regulations which rely heavily on American Bureau of Shipping Rules for Building and Classing Mobile Offshore Drilling Units (ABS MODU rules). USCG has approved the use of other rules and guides as well as industry standards as appropriate to supplement the ABS MODU rules. Due to the high level of activity in deepwater and the limited staff available within companies, we have not undertaken an exhaustive comparative review of the proposed documents to be incorporated by reference with the ABS MODU rules. However, there is a high probability that conflicts may occur. In the event that conflicts do occur, how will the conflict be resolved between MMS and USCG regulations on the same system?
>
> The joint jurisdiction of MMS and USCG over the same systems is confusing to industry, especially when conflicts occur. There are several approaches that we believe MMS and USCG could consider to eliminate the concern over joint jurisdiction. One would be to adopt identical regulations for systems subjected to joint jurisdiction. Or, MMS and USCG could work together to clearly identify lead agencies with the authority to approve each system in lieu of both agencies approving each system. Or, since the concept of verification agents is acceptable to both MMS and USCG, a verification agent that is acceptable to both agencies could review the project utilizing the best regulations and standards for the specific project or system, regardless if the regulations were identical between the two agencies.

Continuing coordination between MMS and USCG is required during the review and approval of OCS floating platforms. For the reasons stated under the preceding Issue No. 2, it is unrealistic to expect MMS and USCG to adopt identical standards because of the different natures of the types of facilities they regulate, and the separate responsibilities assigned to each agency by Congress. Both agencies have worked diligently through various MOUs over the years to adapt their regulatory requirements to changing technology, circumstances, and statutory responsibilities.

USCG is currently revising the regulations at 33 CFR subchapter N. Since these are draft regulations, MMS believes it would be counterproductive at this time to do a complete and detailed comparison between our final subpart I regulations and the USCG proposed version of 33 CFR subchapter N. Prior to finalizing subchapter N, USCG and MMS have agreed to do a detailed comparison of the floating platform requirements of both agencies to identify and eliminate potential conflicts to the maximum extent practicable.

Concerning the matter of CVAs that are acceptable to both MMS and USCG, neither MMS nor USCG believes it should be in the business of certifying or recommending CVAs. Nevertheless, MMS would encourage lessees to submit qualification statements for CVAs that would be acceptable to both MMS and USCG.

Issue No. 4: It Is Unclear What Submissions MMS Expects To Receive

OOC commented concerning proposed § 250.903(b), § 250.910(b) in this final rule:

> * * * Since the structures listed as (1)(2)(3) and (4) are not mentioned in (proposed) § 250.902, it is not clear what information MMS expects to be provided in the application process or in the CVA process. Please clarify.

For clarity in this final rule, language was added to the table in § 250.905(d), (f), and (h) concerning the items listed in proposed § 250.903(b). Briefly summarized, MMS expects to see all structures under our jurisdiction submitted through the normal platform approval process. The PVP is required for all platforms that do not meet standard design criteria for shallow waters. This will always be the case for a floating platform.

Issue No. 5: It Is Unclear What Is Expected of the CVA Process for Floating Platforms

Concerning proposed § 250.905(a), OOC commented:

> * * * The design verification plan requirements are confusing. The proposed regulation appears to be based on CVA processes for fixed platforms. These are not applicable for floating platforms. MMS should write separate requirements for CVA processes for fixed and floating systems. For floating systems, the operator submits the design documentation specified in (1), (2) and (3) directly to the CVA, not to MMS to

give to the CVA. Is this a change in the program? Also, in most cases for a floating system, all the required information will not be given to the CVA at one time, but rather will be given to the CVA in a sequential manner as it is generated. It is recommended that MMS investigate the process used for the floating systems to date and modify the proposed rule accordingly.

OOC provided nearly identical comments on proposed § 250.905(b). Shell provided similar comments. Those proposed subsections were renumbered as §§ 250.912(a) and (b) in this final rule.

As explained above in Issue No. 1, concerning whether subpart I should be broken down to separately address fixed and floating platforms, MMS agrees that a floating platform probably will undergo more complicated design, CVA, and approval processes than a fixed platform. MMS concluded that it is better to allow the companies' engineering staffs to use their judgment in obtaining the various approvals rather than for MMS to impose a rigid step-by-step certification or classification process for the design, fabrication, and installation of each style and permutation of a platform.

MMS has not changed the program with respect to how PVP materials are submitted to the CVA. MMS has always required this information to be directly provided by the operator to both MMS and the CVA. The CVA's responsibilities during the design, fabrication, and installation phases are described in final §§ 250.916, 250.917, and 250.918, respectively. The CVA for each phase will not be able to perform these responsibilities in a proper manner without access to all the documentation submitted to MMS.

MMS agrees with OOC that in most cases, and for floating platforms in particular, required information will not be given to either the CVA or MMS at one time, but rather will be provided in a sequential manner as it is generated. This is to be expected, and is acceptable from our viewpoint. MMS is willing to review Platform Verification and CVA documentation as it becomes available, and there is no requirement in our regulations to submit it at one time. The only MMS requirements with respect to timing are the requirement in new § 250.912(a) that the lessee may not submit its design verification plan before submitting a Development and Production Plan (DPP) or a Development Operations Coordination Document (DOCD), and the requirement in new § 250.912(d) that operators combine fabrication verification plans and installation verification plans for man-made islands.

This final rule should make it easier to obtain approvals for floating offshore platforms. MMS has concluded that it is best to issue this final rule, rather than re-propose it with two separate CVA processes for fixed and floating platforms, as OOC suggests.

Concerning proposed § 250.910(d), located at § 250.916(c) in this final rule, OOC continued:

* * * It should also be recognized that for floating systems, the CVA has been verifying the design to the USCG requirements since MMS had not established design requirements. It will take the CVA longer to verify the design to the new requirements. In the cases where the CVA is also approving the design for Class and/or USCG, they will also have to verify the design to those requirements.

MMS agrees that it may take the CVA longer to verify the design to the new regulatory requirements. For those cases where the CVA is also approving the design for Class and USCG requirements, USCG will also have to verify the design requirements. This process is addressed in the current MOU between MMS and USCG.

OOC and Shell requested that naval architects be included in the list of personnel conducting the design verification described in proposed § 250.905(a). MMS agrees, and § 250.912(a) of our final rule has been amended accordingly.

Concerning proposed § 250.911(f), OOC and Shell requested, ''Please clarify if the fabrication CVA is expected to verify the center of gravity, etc. that is normally considered to be part of the USCG review and approval.''

MMS understands industry's concerns about coordination between MMS and USCG, particularly regarding floating platforms, and added language to final §§ 250.916(b) and 250.917(b) stating, ''For floating platforms, the CVA must ensure that the requirements of the USCG for structural integrity and stability, *e.g.*, verification of center of gravity, etc., have been met.''

Concerning proposed § 250.905(c), (§ 250.912(c) in this final rule), OOC commented, ''We assume that the inspections discussed in (4) are the inspections performed immediately after installation to ensure that no damage was done during the installation activities.''

OOC is correct. The final rule includes revised language in § 250.912(c)(4) to clarify this point. In some cases it may be desirable to conduct intermediate inspections during installation to ensure that the installation is continuing according to plan.

Issue No. 6: The Submission and Review Timeframes for Various Documents Are Unclear

OOC and Shell commented concerning the proposed § 250.904(b) requirement for three copies each of the design verification, fabrication verification, and installation verification plans, now contained in § 250.911(c) of this final rule, that the ''MMS should establish a time frame for approval following the submittal of the required plans.''

MMS does not agree. The industry respondents themselves have all expressed concerns about the complexity of the new subpart I approval processes, and uncertainty about their own ability to provide adequate documentation to obtain the necessary approvals from both MMS and USCG. The submission, review, and approval processes are all very complex. Therefore, MMS concluded that it would be unwise to try to put a scheduled approval process in place for any segment of the PVP. As discussed above under Issue No. 5, MMS agrees with OOC that in most cases, and for floating platforms in particular, required information will not be given to either the CVA or MMS at one time, but rather will be provided in a sequential manner as it is generated. The regulations do not require that all information under the PVP be submitted at one time.

As mentioned earlier in our discussion of Issue No. 2, some conflicts between MMS and USCG cannot be avoided, and this means that there can be no certain schedule for review and approval. In the responsibilities section of the MOU between MMS and USCG, a lead agency is identified not only for each system, but also for each sub-system. For example, each agency is identified as the lead agency for some aspect of the station keeping system (including foundations, moorings, and tethering systems; or dynamic positioning). Each agency must review the design of the station keeping system with respect to foundations, moorings, and tethering systems, since it affects the floating stability of the facility and the drilling and production operations on the facility. Any disagreements will need to be discussed and resolved, and MMS cannot guarantee a certain review and approval schedule in such situations.

Concerning proposed § 250.910(d), now § 250.916(c) in this final rule, OOC commented:

* * * These requirements appear to be based on fixed platforms and are not applicable to floating platforms. The requirement to submit the design CVA

reports within 6 weeks of receipt of the design data for a fixed platform is too short a period. Recommend that the requirement be revised to within 90 days of the receipt of the design data, but at least prior to facility installation. For floating platforms, the complete design data is not provided to the CVA in one package; therefore, there should be some recognition of a phased approach. In all cases, the final report should be issued to MMS prior to installation.

Shell provided similar comments.

MMS agrees with OOC and Shell, and amended final § 250.916(c) to specify that the CVA must submit the design verification report within 90 days of the receipt of the design data. However, MMS has also specified that the design verification report must be submitted before fabrication begins, rather than before installation begins.

Also, OOC and Shell commented concerning proposed § 250.911(f) that the requirement to submit the fabrication CVA reports immediately after completion of the fabrication is not really defined. They recommend that the requirement be revised to within 90 days of the completion of fabrication, but at least prior to facility installation.

MMS agrees with OOC and Shell, and amended final § 250.917(c) to specify that the CVA must submit the fabrication report within 90 days of the completion of fabrication, but before installation begins.

OOC and Shell also commented concerning proposed § 250.912(e) that the requirement to submit the installation CVA reports within 2 weeks of completion of the installation is too short a period. They recommended that the requirement be revised to within 30 days of the completion of the facility installation.

MMS agrees, and amended final § 250.918(c) accordingly.

Issue No. 7: MMS Should Write Clear and Comprehensive Regulations That Do Not Require Later Notices to Lessees and Operators (NTLs) To Explain or Interpret Regulations to Industry

In its cover letter to MMS concerning the proposed rule, OOC commented:

Further, we have heard comment by MMS that either in conjunction or following this rulemaking effort, MMS is considering issuing a Notice to Lessees (NTL) explaining the interpretation of the regulation. We believe that the regulation should be written in a clear, comprehensive fashion such that a NTL, if needed at all, would only cover limited areas. Appropriate areas to be included in a NTL would be such specifics as a time frame for conducting inspection under API RP 2A for existing platforms and a list of acceptable CVAs.

MMS agrees. The agency has written this rule to be as comprehensive and clear as possible to minimize the chances that an NTL will be required. If it is found that an NTL is needed, MMS agrees it should only address limited, site-specific areas, and provide guidance on how to implement the existing regulation.

Issue No. 8: Floating Platforms Designed According to ''Class'' Should Not Need Specific Approval of the MMS Regional Supervisor

Concerning proposed § 250.901(b), both OOC and Shell stated:

If an operator chooses to Class his floating platform, the systems covered by Class should be allowed to be designed to Class rules without seeking specific approval from the Regional Supervisor.

MMS recognizes that the decision to design a platform according to ''Class'' requirements provides a level of safety in verifying the structural stability of the platform. However, since this decision is optional and there is no requirement to maintain the Class of a platform, MMS must ensure that all OCS platforms meet MMS regulations. Therefore, all OCS platforms, including those that the lessee or operator chooses to design according to Class requirements, will continue to be specifically approved by the MMS Regional Supervisor under current regulations.

Concerning proposed § 250.902(j), now § 250.905(j) in this final rule, Shell commented:

The Certification required in (j) 'The design of this structure has been certified by a recognized classification society * * *.' is stated as if the design at the time the application has been made has already been reviewed and approved. At the time the application is made, the design of a floating structure will NOT have been certified by a recognized classification society. We recommend that you restate the Certification to 'The design of this structure *will be* certified * * *'.

MMS cannot agree with the requested word change. Because of the schedule on some projects, MMS receives applications for platforms prior to the design being completed. However, these applications must include evidence that the design is in the process of being certified. Prior to installation, a final certified design must be submitted for approval by the MMS Regional Supervisor.

Concerning proposed § 250.903(a), § 250.910(a) in the final rule, OOC and Shell commented:

If an operator chooses to Class the structure, the systems covered by Class should not be subject to the Verification program, rather the operator should be required to submit a Class certificate once it is issued following the installation of the structure.

In order for MMS to agree with the OOC and Shell proposal, MMS would have to agree to defer to the procedures used to Class each floating platform, and MMS would also have to require that the Class for each floating platform be maintained and renewed for the life of the platform. As explained in its response to the first comment on this issue, MMS will not do that. The PVP is not an optional program in lieu of designing a platform according to Class requirements. This program has served MMS and industry well, and MMS intends to continue to maintain the program of third party verification for platform design, fabrication, and installation. Under the OCS Lands Act, MMS is obligated to oversee oil and gas exploration, development, and production operations on the OCS to ensure that they are conducted in a safe manner. The verification of production platforms is a part of that responsibility.

Issue No. 9: MMS Should Better Define What Is Meant by ''New'' Floating Platforms and ''Major Modifications''

Newfield commented, ''Definitions of 'new' and 'major modification' are vague and require more precise definitions to prevent confusion and interpretation problems.''

Also with respect to new facilities, OOC and Shell commented regarding § 250.800(b) and Subpart I:

1. How is 'new' defined? It should be realized that in many cases there is a long lead time between the initial design of the platform, the facilities, mooring and risers and fabrication and installation. All floating platforms currently in either the late stages of design or being fabricated may not fully comply with all of the proposed regulations. This comment is applicable to other parts of the proposed regulation where 'new' is utilized.

2. How are fixed and floating platforms handled that are reused or relocated to a different block than where they were originally sited? Is the design grandfathered to the rules in place at the time the unit was designed, fabricated and originally installed or will it have to meet any new requirements that have been adopted since the initial installation? Is there a difference in the way fixed platforms are handled from floating platforms?

From MMS's perspective, a ''new platform'' means a newly-constructed platform at a certain location, or a used platform that is either moved to a new site or used for a new purpose. In the first situation, the platform is considered a ''newbuild.'' In the latter situation, it would be a used platform converted for a new use or at a new site. There is no ''grandfathering'' of prior standards for relocated platforms. For either a newbuild or a relocated/new-use platform, the platform would have to meet MMS regulations as they exist at the time the platform design is reviewed (or re-reviewed) by MMS. For fixed platforms, all design, fabrication, and installation requirements would be governed by MMS regulations. Floating platforms would be governed by both MMS and USCG regulations, as described above in the Issue No. 2 discussion concerning the MOU between MMS and USCG.

In the case of a used platform, the design is approved for the new use or site, and the used platform would have to meet the requirements of Section 15 of API RP 2A, which addresses the key aspects of reused platforms. Relocated facilities would have to meet all new requirements, and pass the inspection requirements listed in Section 15 of API RP 2A. The Twenty-first Edition of API RP 2A was incorporated into MMS regulations under a separate rulemaking on April 21, 2003.

Although API RP 2A addresses fixed structures, MMS would apply some of the principles and methodologies outlined in API RP 2A for reused facilities to floating platforms also. In addition, there are certain structural fatigue considerations related to floating platforms that are partly covered in other API standards, such as API RP 2FPS and API RP 2SK, and which would be applicable to reused floating facilities. Finally, a reused floating facility relocated to a new site would be treated as a new facility requiring an API RP 14J hazards analysis.

Once the design for any fixed or floating platform is approved, MMS regulations at the time of the design approval will govern the fabrication and installation phases as well. In that sense, the subpart I regulations are grandfathered when the platform design is approved for a specific platform, use, and location. MMS has always followed this principle under subpart I.

Concerning proposed § 250.900(a), (§ 250.900(a) and (b) in this final rule), OOC commented:

> Although major modification is vaguely defined in 250.900(a)(2), industry is confused by the definition and it is not clear what MMS means by the definition. Either more precise definition is needed or examples need to be given. Is there a difference in major modification to a fixed platform versus a floating platform?

OOC and Shell further commented concerning proposed § 250.903(c), (§ 250.909 in this final rule):

> What constitutes a major modification to a fixed or floating platform? Does it include such things as increased loading due to additional topsides equipment or loading from additional wells or risers?

From MMS's perspective, a major modification would be any modification to a structure that affects loading by more than 10 percent. This definition follows the principle that MMS has used over the years, as well as the guidance in API RP 2A, Section 17, ''Assessment of Existing Platforms,'' Subsection 17.2.6, ''Definition of Significant.'' This definition states: ''Cumulative damage or cumulative changes from the design premise are considered to be significant if the total of the resulting decrease in capacity due to cumulative damage and the increase in loading to cumulative changes is greater than 10 percent.'' Although, the subsection is written to apply to either damage or structural changes, MMS believes this is a good principle to follow for all platforms. This is especially important for floating platforms, because of the stability issues that arise when additional loads are added to floating structures. Thus, when OOC and Shell ask whether a ''major modification'' could include ''increased loading due to additional topsides equipment or loading from additional wells or risers,'' the answer is ''yes.'' Also, repairs to a structure to correct damage could be seen as a major modification if they increase loading on the platform by 10 percent or more.

MMS will evaluate proposed modifications on a case-by-case basis. Language has been added to both § 250.900(b) and § 250.910(c) in this final rule to clarify that a major modification includes any modification that increases loading on a platform by 10 percent or more, and requiring that lessees and operators consult with both MMS and USCG in seeking approval for a major modification to a floating platform.

Issue 10: The Application of American Petroleum Institute (API) Recommended Practice (RP) 14J, and API RP 2FPS to ''New'' Floating Production Platforms Needs Clarification

Concerning proposed § 250.803, ABS commented:

> We note the proposed incorporation of API RP 14J into the revised rules. In this regard, we note that much of 14J was written from the standpoint of use with fixed platforms. With respect to floating structures (such as spars and FPSO's) it is unclear whether the risk assessment methodologies and checklists accompanying the 14J document will adequately cover the integration of vital process and marine systems (such as ballast control, stability, marine system integration, cargo transfer, etc.), where simultaneous operations and cross-overs are prevalent. The hazards assessment methodology proposed by MMS should therefore consider ways to ensure that strict adherence to 14J in carrying out a hazards analysis on a floating installation will address this vital marine/process system relationship.

Concerning proposed § 250.901, ABS commented:

> It is noted in the proposed rulemaking commentary that API RP 2FPS is an umbrella document imposing no new requirements directly. Structural and production facility requirements are specifically referenced throughout § 250. Prior to this rulemaking MMS had no specific rules for marine and other non-production related systems for floating production units, as are found in API RP 2FPS. A specific statement as to MMS intentions relative to these non-production systems would be appropriate.

MMS agrees with ABS that API RP 14J and API RP 2FPS may not by themselves completely address all aspects of floating facilities to be regulated under subpart I. Nevertheless, these two industry references serve very useful purposes. API RP 2FPS provides guidance on all of the associated marine systems, as well as drilling and production systems, and how they fit together and interact with each other. MMS knows of no other standard that performs this function. Though API RP 14J was initially developed to address hazards analysis approaches for drilling and production systems on fixed offshore platforms, these same systems will be installed on floating offshore platforms. Further, the hazards analysis approaches presented in Section 7 of API RP 14J will prove important in considering simultaneous operations and cross-over that will occur on floating offshore platforms. That is why MMS is incorporating these two documents by reference into our regulations, and intends to employ them, as appropriate, in our review of new floating production facilities.

Issue No. 11: The Application of American Petroleum Institute (API) Recommended Practice (RP) 2A to Fixed Production Platforms Needs Clarification

ABS commented concerning proposed § 250.901:

> The document adopts the API–RP2A–WSD. Is the API – RP2A – LRFD not acceptable at this time for any application? Some of the requirements in API – RP2A – LRFD, such as hydrostatic collapse of tubular members for deepwater applications, may be more reasonable than those in WSD. If acceptable, guidance in the regulations should specify load and resistance factors.

Since the early 1980s, MMS has followed the policy currently outlined in § 250.141 of our operating regulations, whereby MMS promotes the use of technology or innovative practices that are not specifically mentioned or otherwise covered under our regulations. For example, § 250.141 tells the lessee or operator that ''You may use alternate procedures or equipment after receiving approval as described in this section.'' The approval must be in writing from either the MMS District or Regional Supervisor. Paragraph (a) of § 250.141 requires that ''Any alternate procedures or equipment that you propose to use must provide a level of safety and environmental protection that equals or surpasses current MMS requirements.'' Paragraph (c) of § 250.141 requires that the lessee or operator submit information or provide an oral presentation to describe the site-specific applications, performance characteristics, and safety features of the proposed alternate procedures or equipment.

Thus, if a lessee or operator believes that the load and resistance factors design (LRFD) version of API RP 2A is more appropriate for its proposed platform than the working stress design (WSD) version, the lessee or operator may submit its arguments to use the former under § 250.141 of MMS operating regulations. As stated previously in this discussion, MMS has already incorporated the Twenty-First Edition of API RP 2A into our regulations under a separate rulemaking dated April 21, 2003.

Issue No. 12: MMS Should Publish a List of Acceptable CVAs for Various Types of Structures

In their cover letter, OOC commented:

> * * *In lieu of submitting a qualification statement and obtaining approval for each CVA for each project, MMS should publish a list of acceptable CVAs for various types structures for which a qualification statement is not required. For example, ABS and DNV for spars and TLPs. If an operator wanted to use a CVA not on the ''approved'' list, then a qualification statement would be required and the CVA would have to be approved.

MMS does not agree with this recommendation. In 1979, when the PVP was first instituted, MMS' predecessor agency maintained a list of acceptable CVAs for various types of offshore platforms and for the various phases of the verification process, as proposed in OOC's comment. However, it soon became apparent that, as a result of the movement of personnel between companies and continuous changes in a company's workload, the qualifications of the companies on this list changed frequently. It was not possible to ensure that a specific company maintained the required expertise to remain on the CVA list on a long-term basis. Also, some companies discovered that being on such a list did not ensure that they would receive any work as a CVA. Therefore, MMS stopped maintaining a list of acceptable CVAs and began to allow OCS lessees to nominate their selection of a company or a person to act as their CVA on a case-by-case basis for each project and phase of the project. This approach was already implemented in our regulations and is continued in the new subpart I under § 250.914.

Issue No. 13: There Should be More Guidance in Proposed §§ 250.902 and 250.903, Now Numbered as Final §§ 250.905 and 250.910, Concerning CVA Responsibilities for Review of (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

Concerning proposed § 250.902, OOC commented:

> * * *We also note that no information has been requested to be submitted in the platform application on the drilling and production risers and tensioning systems for floating platforms even though these are proposed to be covered under the CVA program. What information are we required to provide to either MMS or the CVA on these elements?

OOC made a similar comment regarding proposed § 250.903(b), as follows:

> 1. While it may be prudent to include drilling and production risers and riser tensioning systems in the CVA program for design, it is problematic to include these into the fabrication and installation CVA program. The risers and tensioning systems will be fabricated for wells as needed, they are not all fabricated at one time similar to platform (sic). We question the value returning to the CVA fabrication process each time a riser or tensioning system is fabricated. The risers and tensioning systems are installed on each well as it is drilled. We question the value of having the installation verified through the CVA program. If a conventional marine riser is utilized for drilling operations, it should be excluded from the CVA process.
>
> 2. Since the structures listed as (1)(2)(3) and (4) are not mentioned in § 250.902, it is not clear what information MMS expects to be provided in the application process or in the CVA process. Please clarify.

Concerning proposed § 250.910(b), (§ 250.916(b) in the final rule), OOC commented:

> The scope of work for the CVA design review of drilling and production risers and tensioning systems is not clear. MMS should provide additional guidance on the CVA duties for these elements.

Concerning proposed § 250.912(a), (§ 250.918(b) in the final rule), OOC commented:

> We note that there are no requirements for drilling and production risers and tensioning systems listed in the CVA duties. Although we believe that the installation of these systems should not be included in the CVA's duties, if MMS disagrees and includes them in the CVA process, then the CVA's duties should be specified.

ABS submitted a similar comment concerning proposed §§ 250.911 and 250.912 (§§ 250.917 and 250.918 in the final rule):

> * * * These sections refer to the applicable provisions of the documents in 250.901(a). As API RP 2RD and Spec 17J are specifically design oriented, clarification is required regarding MMS intentions relative to Fabrication and Installation CVA activities.

As an initial matter, and with respect to these comments generally, when MMS requires that an item be reviewed by a CVA under the PVP, that item must be included with the lessee's platform application. As noted by the commentors, API RP 2RD and API Spec 17J are primarily oriented toward the design of risers and unbonded flexible pipe, respectively, and not the fabrication or installation of these risers or pipelines at an offshore platform. (API Spec 17J is discussed more completely in connection with the next issue.) Nevertheless, MMS has required a CVA review for design, fabrication, and installation of drilling and production risers, and riser tensioning systems for all floating platforms, as discussed below.

Second, MMS has added language to the application table in § 250.905 to clarify that the following information required under § 250.910(b) is to be included in a lessee's platform application: (1) Drilling, production and pipeline risers, and riser tensioning systems; (2) turrets and turret-and-hull interfaces; (3) foundations, foundation pilings and templates, and anchoring systems; and (4) mooring or tethering systems. Additionally, language was added in §§ 250.916 through 250.918 to clarify that these four categories of information must be reviewed by a CVA for the three phases of design, fabrication, and installation.

Third, each riser type and the tensioning system for that riser type is to be approved by a qualified CVA for the design phase, the initial fabrication phase, and the initial installation phase for that riser and riser tensioning system. After the first fabrication and first installation of a given type of riser and attendant riser tensioning system, MMS agrees that it is not necessary to return to the CVA fabrication and installation process for each additional riser or riser tensioning system for that riser type. Language has been added to §§ 250.917 and 250.918 to clarify this point.

It is important to bear in mind, however, that each additional riser and riser tensioning system adds a significant load to a floating platform, so the overall platform must be designed to accommodate all the loads imposed by additional risers and riser tensioning systems. MMS will review plans for additional risers and riser tensioning systems to ensure that the overall platform design can accommodate the additional elements.

Concerning proposed §§ 250.911 and 250.912, (§§ 250.917 and 250.918 in the final rule), ABS further commented:

> * * * MMS is encouraged in the recognition of industry design, fabrication and installation requirements more specific than, but fulfilling compliance with the new proposed rules. This is to ensure harmonization of requirements for joint responsibility areas between MMS and USCG as well as with relevant third parties, such as classification societies, and reducing the risk of differing requirements for the same item by different parties.

MMS recognizes the complexities of issuing permits for floating production facilities related to the overlapping responsibilities of MMS and USCG. These processes are, of necessity, further complicated by the third-party reviews of CVAs and classification societies. This will require continuous cooperation and refinement of coordination between MMS and USCG, as well as the various industry standards-setting organizations.

Issue No. 14: Concerning Installation of Unbonded Flexible Flowlines and Pipelines Under §§ 250.803(b)(2)(iii), 250.1002(b)(4), and 250.1007(a)(4), Respectively, It Is Unclear How MMS Will Handle the Independent Verification Agent (IVA) Reviews

OOC and Shell commented concerning proposed § 250.803(b)(2)(iii):

> When does the third party review of unbonded flexible pipe flowlines have to be submitted to MMS? What is MMS going to do with the IVA review? Does the review have to be approved by MMS?

OOC and Shell further commented concerning proposed § 250.1007(a)(4):

> It should be recognized that the third party review may not be available at the time the initial pipeline application is submitted. This requirement should be reworded to say that the third party review must be submitted prior to the pipeline application being approved.

Similarly, ABS submitted the following comment concerning proposed §§ 250.803(b)(2)(iii), 250.1002(b)(4), and 250.1007(a)(4):

> The Independent Verification Agent (IVA) per API SPEC 17J is noted in the Introductory supplementary information of the notice of proposed Rulemaking as being equivalent to the Certified Verification Agent (CVA) per MMS rules. However, this equivalency is not specifically addressed within the above cited proposed rule sections. Such a clarification is suggested for clarity.

In light of these comments, MMS has reconsidered the requirements of API Spec 17J. The IVA review requirements in that standard are intended to pertain only to the design and manufacturing process of unbonded flexible pipe, not the actual installation of the pipe on location. In this context, the IVA described in API Spec 17J does not serve the same role that the CVA serves in subpart I of our regulations. Therefore, §§ 250.803(b)(2)(iii), 250.1002(b)(4), and 250.1007(a)(4) have been modified to require that the lessee or operator installing flowlines or pipelines of unbonded flexible pipe (1) Review the Design Methodology Verification Report, and the IVA's certificate for the design methodology contained in that report, to ensure that the manufacturer has complied with the requirements of API Spec 17J; (2) determine that the flexible pipe is suitable for its intended purpose on the lease or pipeline right-of-way; (3) submit to the MMS District or Regional Supervisor the manufacturer's design specifications for the pipe; and (4) submit to the District or Regional Supervisor a statement certifying that the pipe it has chosen is suitable for its intended use, and that the manufacturer has complied with the IVA requirements of API Spec 17J.

Issue No. 15: The Requirements for In-Service Inspection Plans (ISIPs) Need To Be Clarified, Particularly Concerning Floating Platforms and USCG Responsibility for ISIPs for Floating Platforms.

OOC provided the following comments concerning proposed § 250.902 (§ 250.905 in the final rule):

> Document (i) requires that an in-service inspection plan be submitted for both fixed and floating platforms with the application. In the MOU between the USCG and the MMS, USCG has been given sole jurisdiction of structural inspection requirements for floating platforms, with the USCG copying MMS on approvals and compliance records. Industry is confused over the rationale for MMS to adopt In-service Inspection Plan (ISIP) requirements for floating platforms. MMS should coordinate any requirements for ISIP review and inspection oversight with the USCG, to eliminate a duplicate or parallel program. We also question the timing of the submittal of the inspection plan. Since the first inspection is normally not due for at least a year after installation, we recommend that any ISIP that is required to be submitted not be submitted with the platform application, but within 1 year after installation. Clarification is also needed on the in-service inspection agency jurisdiction for mooring and station keeping systems. It is also unclear what information the MMS expects to see in an ISIP for either a fixed or floating platform. Also, since the ISIP has to be submitted with the platform application, this suggests that each platform has to have an individual inspection plan. It would be less burdensome on both industry and MMS to develop a generic inspection, at least for fixed platforms, that covers the different types of platforms that an operator has with perhaps a table covering the individual platforms.

Shell provided similar comments regarding proposed § 250.902 (final § 250.905).

OOC provided the following comment concerning proposed § 250.916(a) (final § 250.919(a)):

> 1. For floating facilities the In-Service Inspection Program (ISIP) duplicates the vessel inspection program already required and being done by the USCG. MMS should coordinate any requirements for ISIP review and inspection oversight with the USCG, to eliminate duplicate or parallel programs.
>
> 2. Since the proposed regulation calls for submitting an inspection with a platform application, does MMS envision that inspection plans be generated for existing platforms? If so, do they have to be submitted to MMS for review or approval? Does each facility have to have its own plan? Can one plan cover all of an operator's structures or does each structure have to have its own plan?

Shell provided similar comments regarding proposed § 250.916 (final § 250.919), paragraphs (a) and (b).

MMS disagrees with the claim that the requirement for ISIPs is a new and unjustified requirement. ISIPs are required under our current subpart I regulations, so any existing platform not covered by an ISIP would not be in compliance with our regulations.

MMS first implemented the requirement for a periodic structural inspection of all fixed platforms installed on the OCS in April 1988, after it was proposed by the Marine Board of the National Academy of Sciences. Oil and gas industry representatives participated on the Marine Board when it made the recommendation.

The MMS ISIP requirement and the API standards provide starting points for developing ISIPs for fixed and floating offshore platforms. It should be expected that an ISIP for a given facility would have to be modified if subsequent experience indicates that it is not adequately covering a certain aspect affecting the stability or safety of the platform or its associated structures.

MMS disagrees that an ISIP should be provided within 12 months after the installation of an offshore facility, instead of with the platform application. Periodic inspection issues affect the design of an offshore facility, and therefore must be considered during the design of an offshore facility. Periodic inspection issues also must be considered during the initial review by the regulatory agencies. The original designers of a platform are usually best qualified to design the ISIP for that platform. Therefore, MMS encourages lessees and operators to at least consult with their original designers in the development of an ISIP for a platform.

In response to OOC's comment that it is unclear what information MMS expects to see in an ISIP for either a fixed or floating platform, MMS expects the ISIP to reference all relevant API or other industry standards. OOC's observation that it appears that MMS expects each platform to have an individual inspection plan is correct. Each platform should have its own ISIP. However, if a lessee or operator has a number of platforms that are all of the same type, it is acceptable to have one generic ISIP covering all those platforms. The generic ISIP would have to be modified to address the unique environmental conditions affecting each specific platform. Also, for each platform having significant structural features distinguishing it from the generic type, the generic ISIP would have to be tailored to accommodate the significant distinguishing structural features of that platform.

MMS also disagrees that the USCG has sole jurisdiction for the structural inspection requirements for floating platforms. The USCG has the lead responsibility for the floating facility hull. However, USCG does not have lead responsibility for the turret, turret/hull interface; the risers and their tensioning systems and interface with the hull; the foundations and anchoring systems; or the mooring or tethering systems. MMS has the lead responsibility for these systems, any or all of which could adversely affect the safety and stability of the hull of a floating facility. Since the hull and interconnected MMS-regulated systems are so intertwined, to be relevant and complete an ISIP should address all the systems within the regulatory responsibility of both MMS and USCG.

MMS and USCG currently meet regularly to discuss their concerns with various aspects of each platform submission, and to work out regulatory differences prior to responding to the submitting companies. This process will continue, to ensure that submitting companies will not be given conflicting instructions. Because MMS and USCG hold ongoing discussions concerning their respective responsibilities for offshore floating platforms, the agencies may, from time to time, amend their MOU regarding oil, gas, and mineral exploration and production operations on the OCS.

Issue No. 16: For Platforms Subject to the Platform Verification Program, MMS Should Provide More Clarity Concerning Which Documents Go to MMS and Which Go to the CVA

In its cover letter, OOC commented:

> It is also unclear why MMS needs to get a copy of many of the items that are submitted directly by the operator or design firm to the CVA for review. For example, why does MMS need to receive abstracts of the computer programs used for design when the same information must be given to the CVA? It appears to be redundant for MMS and the CVA to review the same documents. Since a number of floating platforms have now been permitted, we recommend that MMS consider revising the structure application and CVA plan to better reflect the actual way floating platform projects are sequenced and to consider what information MMS needs to review and what needs to be given directly to the CVA * * *.

Concerning proposed § 250.902 (final § 250.905), OOC and Shell commented:

> For platforms subject to the Platform Verification Process, the rationale for submitting a full application to MMS, including a complete set of structural drawings, etc., is unclear since the information will also be provided to the certification agency to verify the design. It would appear to be more appropriate to submit (a),(b),(c) and (j) to MMS with the rest of the information submitted to the CVA. In many instances all of the information required is not available at the time the application needs to be made for a floating platform in order to kick off the CVA program.

From a regulatory perspective, it is important to remember that the CVA process was initiated because MMS does not maintain an engineering staff large enough to comprehensively review all structural engineering designs for platforms on the OCS. Thus, a CVA helps ensure that all regulatory requirements are met. However, because of our custodial responsibility for all information related to the design and structural integrity of offshore platforms, it is essential that MMS receive all the same documents and correspondence that the lessee or operator provides to its CVA concerning the design, fabrication, and installation of a fixed or floating platform. This includes the computer programs used for design that OOC referred to in its cover letter. For MMS to stay current with the industry it regulates, we must stay abreast of the various types of software that the industry uses on a routine basis.

Concerning the observation by OOC and Shell that sometimes all required information is not available at the time the application for a floating platform needs to be made, MMS understands that design, fabrication, and installation sequences do not always follow a set pattern. MMS is always willing to work with lessees and operators to accept partial submittals of information, as they become available, to complete what is a necessarily complex permitting process.

Concerning proposed § 250.904(b), (§ 250.911(c) in the final rule), OOC commented that MMS may need to provide more guidance to the CVA to ensure that they are only verifying the operator's proposed design to ensure that it meets the required regulations, not conducting a complete design analysis.

Although MMS agrees with OOC's premise that the CVA primarily functions to ensure that the lessee's or operator's design, fabrication, or installation meets regulatory requirements, it is important to remember that oftentimes the offshore industry is trying out new technology or innovative practices. For innovative proposals which could involve novel components or structures, MMS will require the lessee's CVA to conduct a complete design analysis.

Issue No. 17: Further Clarification Is Needed Concerning the Structural Fatigue Requirements in Proposed §§ 250.913 and 250.914 (Final §§ 250.908 and 250.903(b))

Concerning proposed § 250.913, OOC commented:

> The table does not appear to take into account the minimum requirements in API RP 2RD and 2SK. We recommend that the table be amended to meet the minimum requirements required in the documents incorporated by reference unless MMS is intending to relax those requirements. While we recognize that the table only contains absolute minimum requirements, we note that Class society requirements have a higher minimum threshold that must be met for Classed structures.

MMS agrees with OOC's comment concerning the minimum requirements contained in the industry standards that are included as documents incorporated by reference in § 250.901. Section

250.908 of the final rule has been rewritten to provide clarity.

Also concerning proposed § 250.913 (§ 250.908 in the final rule), ABS commented:

The current practice on fatigue safety factors are based on API RP 2T considering repairability, inspectability and criticality (redundancy) of the members and joints. The API RP 2T fatigue requirements are widely used in the site specific floating structures (TLPs, column-stabilized units, spars, etc.). The recommended fatigue safety factors (2 and 3) consider only one (redundancy) of these three factors. For the deck structure, which is above the water line, these safety factors are appropriate because it is accessible for inspections and repairs. However, for the hull structure, which is always below the water line, the recommended fatigue safety factors may not be appropriate because good quality inspections and repairs will be difficult to carry out in some areas of the hull. The Rules should also indicate that the other two factors need to be considered if applicable. The following are the safety factors normally used for the hull structure of a site-specific floating structure in current practice.

Criticality	Inspection	Repair	Factor of safety
Critical	Easily inspectable	Field Repair	5
Critical	Difficult or Non-inspectable	Difficult or Non-repairable	10
Non-Critical	Easily inspectable	Field Repair	3
Non-Critical	Difficult or Non-inspectable	Difficult or Non-repairable	5

Requirements for the fabrication, installation, and inspection of the hull of floating structures, and the appropriate safety factors to use, are under the jurisdiction of the USCG. The structural fatigue safety factors listed in proposed § 250.913 (final § 250.908) refer to fixed platforms. For fixed platforms, which have a long history of proven performance, MMS prefers to rely on the safety factors recommended by the referenced documents in § 250.901. The safety factors in those documents are based on industry consensus, and may be re-evaluated as industry gains even more experience. They can be changed later by industry consensus, and those changes in turn incorporated by MMS.

Concerning proposed § 250.914 (now § 250.903(b)), OOC and Shell commented that it is not clear where the records on the origin and material test results are to be kept on all primary structural materials covered by this section.

The records on the primary structural materials should be kept at the same location that the lessee or operator specifies in item (j) of the table in final § 250.905. The regulatory language of final § 250.903 has been modified to make this clear.

Issue No. 18. The Proposed Rule Provides Inadequate Guidance on the Use of Shallow Hazards and Geological Surveys in Siting Platforms

ABS submitted the following comment concerning proposed § 250.915 (§ 250.907 in the final rule):

4. It would be helpful for the MMS to provide guidance as to the acceptance criteria for faults such as the minimum distance from the faults to the foundation and what type of fault studies are recommended. This issue has not been addressed in any of the referenced documents listed in § 250.901. Faults have been encountered in deepwater applications.

5. It will be useful for the offshore industry if MMS's policy on the required pile capacity at first oil is specified in the CFRs.

MMS reviewed the requirements for shallow hazards, geologic, and subsurface surveys in our former subpart I, and compared them to the requirements already incorporated in the twenty-first edition of API RP 2A and the API documents to be incorporated by reference by this rule. Based on this comparison, MMS believes that it was unwise to remove so many of our survey requirements in the proposed rule. However, MMS believes that API RP 2A and the other API documents more than adequately address many of the subsurface issues that arise in designing various types of foundations and pilings. Accordingly, MMS has restored an abridged version of our former requirements to the final rule. MMS has inserted the abridged hazard, geologic, and subsurface survey requirements into a new § 250.906 in the final rule.

Section 250.915 in the proposed rule dealt with the requirement for a minimum 500-foot interval between a soil boring and a foundation piling. The sections in the final rule have been renumbered and rearranged so that the proposed § 250.915 is now final § 250.907.

In answer to ABS' first question concerning "acceptance criteria for faults such as the minimum distance from the faults to the foundation and what type of fault studies are recommended," MMS believes that such judgments have to be made on a case-by-case basis depending on the design of the platform and the nature of the sediments into which its foundations or anchors are to be set. The abridged survey requirements in final § 250.906 will enable the lessee or operator to make such determinations for its proposed platform.

Concerning ABS's second request for us to specify "MMS's policy on the required pile capacity at first oil," MMS believes that judgments on pile capacity again will have to be made case-by-case, based on the results of the shallow hazard, geologic, and subsurface surveys required by § 250.906 of this final rule.

Issue No. 19: Respondents Disagree With the Proposed § 250.915(a) Requirement (Now § 250.907(a)) for Fixed or Bottom-Founded Platforms and Tension Leg Platforms That the Maximum Distance From a Foundation Pile to a Soil Boring Must Not Exceed 500 Feet

OOC and Shell commented on proposed § 250.915(a) (now § 250.907(a) in this rule) as follows:

1. Spatial variability of soil properties on the continental shelf is much more of an issue than for deepwater sites. For jackets on the shelf, maximum distance between borings of 500 ft. is reasonable for deterministic designs with conventional safety factors. However, it is possible to have cases where multiple borings are spaced farther apart, but the uncertainty at the platform site may be explicitly quantified and specific safety factors developed accordingly.

2. In lieu of the prescriptive requirement as proposed, the wording from ISO/DIS 19901–4 could be adopted:

Geotechnical and Foundations Design Considerations. Results of previous integrated geoscience studies and experience at the site may enable the design and installation of additional structures without additional investigation. The onsite studies should extend throughout the depth and aerial extent of soils that will effect or be affected by installation of the foundation elements. The number and depth of borings and extent of soil testing will depend on the soil variability in the vicinity of the site, environmental design conditions (*e.g.* earthquake loading and slope instability) to be considered in the foundation design, the structure type and geometry, and the definition of geological hazards and constraints.

3. For TLPs in deepwater, the industry practice is to conduct an integrated geotechnical/geology study of the site to assess spatial variability of soil stratigraphy and physical properties. Given the same depositional environment and geologic processes, practice has shown at several prominent deepwater basins that borings up to 10 miles apart do not produce appreciably different pile sizes considering the same load. Also, the uncertainty in soil properties at the platform site may be explicitly quantified and specific safety factors developed accordingly.

ABS submitted the following comment concerning proposed § 250.915 (final § 250.907):

* * * It will be very helpful to the offshore industry to clarify requirements as to the maximum distance of the soil boring from the foundation piles and number of borings. It would also be helpful to clarify if the borings can be replaced by other means of taking soil samples such as CPT or by a combination of geotechnical investigation and geophysical survey.

MMS does not agree with OOC, Shell, and ABS. None of their proposals is as stringent as what MMS has proposed, *i.e.*, site-specific borings within 500 feet of the proposed foundation pile. In the deepwater areas of the OCS, particularly in the GOM, there are slope and abyssal areas that are much more geologically active than the relatively shallow and familiar areas of the OCS. There are highly active slumping and faulting zones in deepwater areas that exhibit stratigraphic shallow water flows and mud volcanoes. MMS does not believe that floating production systems in these areas should be anchored without site-specific soil boring information.

The policy currently outlined in § 250.141 of our regulations promotes the use of alternative technology or innovative practices that are not specified or otherwise covered under our regulations. Such technologies and practices may be tried on a case-by-case basis, so long as they ''provide a level of safety and environmental protection that equals or surpasses current MMS requirements.''

Thus, if a lessee or operator believes that for a proposed platform on a specific site it can use alternate means to assure secure foundations for the facility or its anchoring systems, it can present its evidence to the MMS Regional Supervisor under the provisions of § 250.141.

Issue No. 20: Respondents Disagree With the Proposed § 250.915(b) (Final § 250.907(b)) Requirement That for Deepwater Floating Platforms Utilizing Catenary or Taut-Leg Moorings, Borings Must Be Taken at the Most Heavily Loaded Anchor Location, at Anchor Points Approximately 120 and 240 Degrees Around the Anchor Pattern From That Boring, and as Necessary to Establish a Suitable Soil Profile

Concerning proposed § 250.915(b), OOC and Shell commented as follows:

Recognizing that deepwater developments with moored floaters and many subsea wells may cover a very large lateral extent (with the layout in a constant state of flux), an alternative site investigation strategy would be to base geotechnical data collection locations on the prevailing geology rather than specific facility locations. An integrated geotechnical/geology study of the development area is required for this methodology ''*i.e.*, stratigraphy must be known at any specific foundation location and uncertainties quantified. Specific safety factors may be developed accordingly.

OOC further noted, ''This section is prescriptive in nature and we recommend that a performance based requirement be adopted.''

Again, MMS disagrees with OOC and Shell for the same reasons as discussed in the preceding issue concerning the maximum distance from a foundation pile to a soil boring. If a lessee or operator believes that for a proposed platform on a specific site it should use a different boring pattern, or alternate means to assure a secure anchoring pattern for a floating facility, it can present its arguments for a different boring pattern, or alternate method to the MMS Regional Supervisor under the provisions of § 250.141.

Issue No. 21: It Is Not Clear Where the Records Required by Proposed § 250.918 (Final § 250.903) Must Be Kept

OOC and Shell maintained that it is not clear where the records should be maintained with respect to the proposed § 250.918 requirements (now in § 250.903) to keep as-built drawings, design assumptions and analyses, summary of fabrication and installation nondestructive examination records, and inspection results from the proposed § 250.916 inspections (now in § 250.919). Again, these records should be kept at the same location that the lessee or operator specifies in item (j) of the table in final § 250.905. The regulatory language in final § 250.903 has been modified to make this clear.

Issue 22: Several of the Industry Standards To Be Incorporated Into MMS Regulations at § 250.901(a) Are in Conflict With Each Other, and MMS Should Stay Involved in the Updating of Industry Standards Incorporated by Reference

OOC submitted the following comments:

Also we recognize that these industry documents are in many cases written as ''stand alone'' documents and that conflicts between documents may occur. For example, while reviewing API RP 510 to determine if it was appropriate to incorporate by reference by MMS, it was discovered that in several places it conflicted with API RP 14C. Industry, due to the high level of activity in deepwater and the limited staff available, has not conducted an exhaustive review to determine if conflicts occur between the proposed documents to be incorporated and other documents incorporated by reference. * * *Industry cautions that they have not made an exhaustive review of all of the standards to ensure that there are no conflicts between the standards. If there are conflicts, these will be identified as these standards and codes are applied in conjunction with one another.
* * * A number of these recommended practices and standards are in the process of being revised to address deepwater facility requirements. MMS should stay up-to-date, and where possible participate, in the revision of these recommended practices and standards, so that new additions of the recommended practices or standards can be readily incorporated into the MMS regulations. For example, industry notes that there is confusion within API RP 2A, 21st edition that needs clarification. In at least three sections (life safety exposure, consequences of failures, inspection levels) of the RP, platforms are divided into Level 1, Level 2 and Level 3 categories; however, the definitions for Level 1, 2 and 3 are different. Therefore, when a platform is generally referred to as a Level 1 platform or a Level 3 platform, confusion is created on what that means. As API revises the documents to element [sic] the confusion, MMS should be involved so they can adopt the changes.

MMS agrees that the best method for having a working knowledge of potential revisions and additions to industry standards is to participate in the meetings of the standard setting committees. MMS has assigned technical personnel as representatives and alternates to various API, International Standards Organization (ISO), American Concrete Institute, American Society of Mechanical Engineers, American Society for Testing and Materials, American Welding Society, Institute of Electronic and Electrical Engineers, National Association of Corrosion Engineers, and International Association of Oil and Gas Producers committees. MMS also monitors the work of other industry standards associations and committees.

MMS agrees that there may be conflicts between the specific requirements of some of the industry standards incorporated by reference into MMS regulations. Whenever these conflicts are found, MMS provides interim clarifications in Notices to Lessees and Operators (NTLs). We post these NTLs on the MMS web page. As necessary, MMS subsequently makes clarifying revisions to its regulations. Through use of these mechanisms, MMS and industry can work through the inevitable conflicts that will arise either through contradictory industry standards or contradictory Federal standards.

Issue 23: MMS Should Consider Incorporating Several Additional Industry Standards Into the MMS Regulations at § 250.901(a)

Both OOC and Shell recommended that MMS consider adopting API RP 2I, ''In-Service Inspection of Mooring Hardware for Floating Drilling Units.'' OOC further commented:

In many cases, all or portions of a floating production are fabricated outside of the United States and welding standards that MMS has deemed for as [sic] equivalent (such as Euronorm) to AWS standards for individual projects are used. MMS should either consider incorporating by reference these equivalent standards or should publish a list of welding standards that they have deemed to be equivalent to AWS standards in lieu of each project having to obtain approval for utilizing an alternate welding standard.

MMS agrees that API RP 2I, second edition, would be a valuable industry standard to consider for incorporation by reference into 30 CFR part 250, subparts A and I. API RP 2I is specifically written to address the inspection, and potential failure modes, of mooring chain and wire rope for MODUs, which frequently move from location to location. Moreover, the information provided in API RP 2I on failure modes, inspection methods, and repair methods also could be useful in the development and implementation of an ISIP plan (§ 250.917) for other types of offshore floating facilities that remain on station for longer periods of time. Based on OOC's and Shell's recommendation, MMS reviewed API RP 2I, ''In-Service Inspection of Mooring Hardware for Floating Drilling Units,'' and agrees that it should be considered for incorporation by reference into 30 CFR Part 250. However, because MMS did not initially propose that API RP 2I be incorporated by reference during the proposed rulemaking process, we have decided not to incorporate it into the final rule. It will be proposed in a subsequent rulemaking to provide the regulated community an opportunity to comment on its incorporation into 30 CFR Part 250.

As additional pertinent industry standards are identified or developed, MMS will occasionally revise its regulations to incorporate certain standards into its regulations in conformance with the Administrative Procedure Act. In those instances in which offshore facilities, both floating and fixed, are fabricated outside of the United States, foreign industry standards must receive prior approval in accordance with 30 CFR 250.901(b), which states, ''* * * You may also use alternative codes, rules, or standards, as approved by the Regional Supervisor, under conditions enumerated in § 250.141, paragraphs (a), (b), and (c).'' MMS has not ruled out the incorporation by reference of foreign or international standards into its regulations. During the past 2 years MMS has incorporated by reference one ISO standard into our regulations.

Derivation Table

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

New section	Previous regulation section
§ 250.900 What general requirements apply to all platforms?	§ 250.900; New requirement.
§ 250.901 What industry standards must your platform meet?	§ 250.900(g); § 250.907(b), (c), (d); § 250.908 (b), (c), (d), (e); New requirements.
§ 250.902 What are the requirements for platform removal and location clearance?.	§ 250.913 (Subpart Q since May 17, 2002)
§ 250.903 What records must I keep?	§ 250.914
§ 250.904 What is the Platform Approval Program?	New
§ 250.905 How do I get approval for the installation, modification, or repair of my platform?.	§ 250.901(a), (b)
§ 250.906 What must I do to obtain approval for the proposed site of my platform?.	§ 250.90(b), (c), (d), (e)
§ 250.907 Where must I locate foundation boreholes?	New Requirements.
§ 250.908 What are the minimum structural fatigue design requirements?.	§ 250.907(c)
§ 250.909 What is the Platform Verification Program (PVP)?	New.
§ 250.910 Which of my facilities are subject to the PVP?	§ 250.902; New requirements.
§ 250.911 If my platform is subject to the PVP, what must I do?	§ 250.902; New requirements.
§ 250.912 What plans must I submit under the PVP?	§ 250.902; New requirements.
§ 250.913 When must I resubmit PVP plans?	§ 250.902; New requirements.
§ 250.914 How do I nominate a CVA?	§ 250.902; § 250.903(b)
§ 250.915 What are the CVA's primary responsibilities?	§ 250.903(a)
§ 250.916 What are the CVA's primary duties during the design phase?	§ 250.903(a)(1)
§ 250.917 What are the CVA's primary duties during the fabrication phase?.	§ 250.903(a)(2)
§ 250.918 What are the CVA's primary duties during the installation phase?.	§ 250.903(a)(3)
§ 250.919 What in-service inspection requirements must I meet?	§ 250.912(a),(b); New requirements.
§ 250.920 What are the MMS requirements for the assessment of platforms?.	New requirements.
§ 250.921 How do I analyze my platform for cumulative fatigue?	New requirements.

Procedural Matters

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) This 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 this 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. The economic analysis prepared for this 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 × 6 = $18 million]. The economic analysis for this rule is available from the Department of the Interior; Minerals Management Service; Engineering & Operations Division; Mail Stop 4020; 381 Elden Street; Herndon, Virginia 20170–4817; Attention: William Hauser.

(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 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 many precedents for regulating offshore production platforms and pipelines to promote environmental protection and human safety under the OCS Lands Act. While this final rule contains many new regulatory requirements for lessees and operators seeking to build new floating production facilities, the incorporation of these standards does not represent a significant change to industry practices because most of these standards are already being utilized by industry.

Regulatory Flexibility (RF) Act

The DOI certifies that this rule 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 lessees classified as small entities would submit plans for deepwater floating platforms in any given year. Most likely, these lessees would be involved 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, MMS concludes 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 at (888) 734–3247.

Small Business Regulatory Enforcement Fairness Act (SBREFA)

This rule is not a major rule under SBREFA (5 U.S.C. 804(2)). 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 the 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 lessees would submit plans for deepwater floating platforms in any given year. Most likely, these lessees' involvement would be 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 rule on individual operators would be reduced significantly. Therefore, MMS concludes that the rule would not have a significant economic impact on a substantial number of small entities.

Paperwork Reduction Act (PRA) of 1995

This rule contains a collection of information that MMS submitted to OMB as part of the proposed rulemaking process for review and approval under § 3507(d) of the PRA. OMB approved the information collection for a total of 37,194 burden hours (OMB control number 1010–0149). The title of the collection of information for this rule is ''30 CFR 250, Subparts J, H, and I, Fixed and Floating Platforms and Structures.''

As the information collection requirements in the final rule remain unchanged from the proposed rule, a resubmission to OMB for approval of the burden normally would not be required prior to publishing these final regulations. However, during the period between proposed and final rules, the OMB approval of the burden for the proposed collection of information was due to expire (March 31, 2005). Also during this interim period, the information collection burden for the current subpart I regulations (1010–0058) came up for renewal. As required by the Paperwork Reduction Act, to renew the current subpart I information collection burden, we consulted with several respondents and revised the burden estimates and number of responses.

Where applicable, we incorporated these updated burden adjustments in the request that we submitted to OMB to renew the information collection burden for the proposed rulemaking (1010–0149). OMB approved that renewal for a total of 48,500 hours, with a current expiration date of March 31, 2008. However, MMS estimates that this final rulemaking will only increase the individual hour burdens approved for the current regulations in subpart H (1010–0059), subpart I (1010–0058), and subpart J (1010–0050), by: 3,300 hours for subpart H; 5,160 hours for subpart I; 2,700 hours for subpart J; 11,160 total burden hour increase.

The revisions to subpart A of 30 CFR part 250 in this final rule do not affect the information collection aspects of those regulations. These are currently approved under OMB control numbers 1010–0114.

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. MMS 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 information collected under subparts H and J to ensure proper construction of production safety systems and pipelines.

When the final regulations take effect, the new information collection burdens for subparts H and I will be incorporated with their respective collections of information for those current regulations. OMB control number 1010–0149 will supersede 1010–0058 and become the new control number for the information collection burdens in subpart I. Its title will be changed to delete the references to subparts H and J.

The 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 approved requirements in subparts H and J and all of the requirements in subpart I. In the writing of the final rule, burdens have been reassigned to new section citations. However, as noted earlier, the burdens themselves have remained unchanged from the proposed rule. The new citations as well as the citations from the proposed rule are noted below.

Rule sections	Reporting or recordkeeping requirement	Hour burden per response/record (hours)	Annual number of responses	Annual burden hours
New Subpart H Requirements				
800(b)	NEW: Submit CVA documentation under API RP 2RD.	50	60 submissions	3,000
803(b)(2)(iii)	NEW: Submit CVA documentation under API RP 17J.	50	6 submissions	300
Subpart I				
900(a), (b); 901(b); 903; 905; 906; 907; 909; 901(c), (d); 912; 913.	Submit application to install new platform or floating production facility or significant changes to approved applications, including use of alternative codes, rules, or standards; and Platform Verification Program plan for design, fabrication and installation of new, fixed, bottom-founded, pile-supported, or concrete-gravity platforms and new floating platforms. Consult as required with MMS and/or USCG. Re/Submit application for major modification(s)/repair(s) to any platform and related requirements.	30	331 applications	9,930
900(b)(5)	Submit application for conversion of the use of an existing mobile offshore drilling unit..	24	30 applications	720
900(c)	Notify MMS/USCG within 24 hours of damage and emergency repairs and request approval of repairs..	16	9 notices/requests	144
901(a)(6), (a)(7), (a)(8)	NEW: Submit CVA documentation under API RP 2RD, API RP 2SK, and API RP 2SM..	100	6 submissions	600
901(a)(10)	NEW: Submit hazards analysis documentation under API RP 14J..	600	6 submissions	3,600
903*	Record original 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..	100	136 lessees	13,600
911(c), (d), (f); 917	Submit interim and final CVA reports and recommendations on fabrication phase, including notice of fabrication procedure changes or design specification modifications..	100	6 submissions	600

Rule sections	Reporting or recordkeeping requirement	Hour burden per response/ record (hours)	Annual number of responses	Annual burden hours
914	Submit nomination and qualification statement for CVA..	16	21 nominations	336
916	Submit interim and final CVA reports and recommendations on design phase..	200	31 reports	6,200
918	Submit interim and final CVA reports and recommendations on installation phase..	60	6 submissions	360
919	Develop in-service inspection plan and submit annual (November 1 of each year) report on inspection of platforms or floating production facilities, including summary of testing results..	GOM 45 POCS 80	130 lessees 6 operators	5,850 480
900 thru 921	General departure and alternative compliance requests not specifically covered elsewhere in Subpart I regulations..	8	10 requests	80
	New Subpart J Requirements			
1002(b)(5)	NEW: Submit CVA documentation under API RP 2RD.	75	12 submissions	900
1007(4)(iii), (iv)	NEW: Submit CVA documentation under API RP 17J.	150	12 submissions	1,800
Total Hour Burden			818	48,500

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

A Federal agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The public may comment, at any time, on the accuracy of the information collection burden in this rule and may submit any comments to the Department of the Interior; Minerals Management Service; Attention: Rules Processing Team; Mail Stop 4024; 381 Elden Street; Herndon, Virginia 20170–4817. If you wish to email your comments to MMS, the address is: *rules.comment@mms.gov*. You may also submit comments on the burdens through *https://ocsconnect.mms.gov*.

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 rule, the annual incremental cost of complying with this regulation for approximately 98 businesses will be about $37,194 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. MMS does not believe that paying this cost will result in any takings. Thus, the DOI does not need to prepare a Takings Implication Assessment under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights. The 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 OMB 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 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.

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. MMS has analyzed this rule under the criteria of the NEPA and 516 Departmental Manual 6, Appendix 10.4C(1). MMS completed a Categorical Exclusion Review for this action on November 20, 2000, and concluded that "the 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.

Consultation and Coordination With Indian Tribal Governments (Executive Order 13175)

In accordance with Executive Order 13175, this rule does not have tribal implications that impose substantial direct compliance costs on Indian tribal governments.

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: June 22, 2005.

Chad Calvert,

Acting Assistant Secretary—Land and Minerals Management.

■ For the reasons stated in the preamble, the MMS amends 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 § 250.490(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 250.921, 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. Add entries in alphanumerical order for 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;

■ B. Revise entries for ACI Standard 318–95, ACI 357R–84, AISC Standard Specification for Structural Steel Buildings, API RP 2A–WSD, 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); § 250.908(a); § 250.920(a)(b)(c)(e)

Title of documents	Incorporated by reference at
* * * * * * *	
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 Order 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 Order 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, API Order No. G02T02.	§ 250.901(a)(9)
* * * * * * *	
API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001, API Order No. G14J02.	§ 250.800(b); § 250.901(a)(10)
* * * * * * *	
API Spec 17J, Specification for Unbonded Flexible Pipe, Second Edition, November 1999, including errata (May 25, 2001) and Addendum 1 (June 2003), Effective Date: December 2002, API Order 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.	§ 250.901(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 § 250.199, in paragraph (e), the heading of the first column, and the first column in paragraph (e)(8) are revised to read as follows:

§ 250.199 Paperwork Reduction Act statements—information collection.

* * * * *

(e) * * *

30 CFR 250 subpart/title (OMB control number)	Reasons for collecting information and how used
* * * * * * *	
(8) Subpart I, Platforms and Structures (1010–0149).	
* * * * * * *	

■ 5. In § 250.800, the existing text 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 must do all of the following:

(1) Comply with API RP 14J (incorporated by reference as specified in 30 CFR 250.198);

(2) Meet the drilling and production riser standards of API RP 2RD (incorporated by reference as specified in 30 CFR 250.198);

(3) Design all stationkeeping systems for floating facilities to meet the standards of API RP 2SK (incorporated by reference as specified in 30 CFR

250.198), as well as relevant U.S. Coast Guard regulations; and

(4) Design stationkeeping systems for floating facilities to meet structural requirements in subpart I, §§ 250.900 through 250.921 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 production platforms, you must comply with the following production safety system requirements, in addition to the requirements of § 250.802 of this subpart and the requirements of API RP 14C (incorporated by reference as specified in 30 CFR 250.198).

(b) * * *

(2) * * *

(iii) If you are installing flowlines constructed of unbonded flexible pipe on a floating platform, you must:

(A) Review the manufacturer's Design Methodology Verification Report and the independent verification agent's (IVA's) certificate for the design methodology contained in that report to ensure that the manufacturer has complied with the requirements of API Spec 17J (incorporated by reference as specified in 30 CFR 250.198);

(B) Determine that the unbonded flexible pipe is suitable for its intended purpose on the lease or pipeline right-of-way;

(C) Submit to the MMS District Supervisor the manufacturer's design specifications for the unbonded flexible pipe; and

(D) Submit to the MMS District Supervisor a statement certifying that the pipe is suitable for its intended use and that the manufacturer has complied with the IVA requirements of API Spec 17J (incorporated by reference as specified in 30 CFR 250.198).

* * * * *

■ 7. Subpart I is revised to read as follows:

Subpart I—Platforms and Structures

General Requirements for Platforms

Sec.

Subpart I—Platforms and Structures

General Requirements for Platforms

§ 250.900 What general requirements apply to all platforms?

(a) You design, fabricate, install, use, maintain, inspect, and assess all 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.

(b) You must also submit an application under § 250.905 of this subpart and obtain the approval of the Regional Supervisor before performing any of the activities described in the following table:

Activity requiring application and approval	Conditions for conducting the activity
(1) Install a platform. This includes placing a newly constructed platform at a location or moving an existing platform to a new site.	(i) You must adhere to the requirements of this subpart, including the industry standards in § 250.901. (ii) If you are installing a floating platform, you must also adhere to U.S. Coast Guard (USCG) regulations for the fabrication, installation, and inspection of floating OCS facilities.
(2) Major modficatiion to any platform. This including any structural changes that materially alter the approval plan or cause a major deviation from approved operations and any modification that increases loading on a platform by 10 percent or more.	(i) You must adhere to the requirements of this subpart, including the industry standards in § 250.901. (ii) Before you make a major modification to a floating platform, you must obtain approval from both the MMS and the USCG for the modification.
(3) Major repair of damage to any platform. This includes any corrective operations involving structural members affecting the structural integrity of a portion or all of the platform.	(i) You must adhere to the requirements of this subpart, including the industry standards in § 250.901. (ii) Before you make a major repair to a floating platform, you must obtain approval from both the MMS and the USCG for the repair.
(4) Convert an existing platform at the current location for a new purpose.	(i) The Regional Supervisor will determine on a case-by-case basis the requirements for an application for conversion of an existing platform at the current location. (ii) At a minimum, your application must include: the converted platform's intended use; and a demonstration of the adequacy of the design and structural condition of the converted platform. (iii) If a floating platform, you must also adhere to USCG regulations for the fabrication, installation, and inspection of floating OCS facilities.

Activity requiring application and approval	Conditions for conducting the activity
(5) Convert an existing mobile offshore drilling unit (MODU) for a new purpose.	(i) The Regional Supervisor will determine on a case-by-case basis the requirements for an application for conversion of an existing MODU. (ii) At a minimum, your application must include: the converted MODU's intended location and use; a demonstration of the adequacy of the design and structural condition of the converted MODU; and a demonstration that the level of safety for the converted MODU is at least equal to that of re-used platforms. (iii) You must also adhere to USCG regulations for the fabrication, installation, and inspection of floating OCS facilities.

(c) 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. If you make emergency repairs on a floating platform, you must also notify the USCG.

(d) You must determine if your new platform or major modification to an existing platform is subject to the Platform Verification Program (PVP). Section 250.910 of this subpart fully describes the facilities that are subject to the PVP. If you determine that your platform is subject to the PVP, you must follow the requirements of §§ 250.909–250.918 of this subpart.

(e) MMS will cancel your approved platform installation permits one year after the approval is granted if the platform is not installed. If MMS cancels your permit approval, you must resubmit your application.

§ 250.901 What industry standards must your platform meet?

(a) In addition to the other requirements of this subpart, your plans for platform design, analysis, fabrication, installation, use, maintenance, inspection and assessment must, as appropriate, conform to:

(1) American Concrete Institute (ACI) Standard 318, Building Code Requirements for Reinforced Concrete, plus Commentary, (incorporated by reference as specified in § 250.198);

(2) ACI 357R, Guide for the Design and Construction of Fixed Offshore Concrete Structures, (incorporated by reference as specified in § 250.198);

(3) American Institute of Steel Construction (AISC) Standard Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design, with Commentary, (incorporated by reference as specified in § 250.198);

(4) American Petroleum Institute (API) Recommended Practice (RP) 2A—WSD, Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms-Working Stress Design, (incorporated by reference as specified in § 250.198);

(5) API RP 2FPS, Recommended Practice for Planning, Designing, and Constructing Floating Production Systems, (incorporated by reference as specified in § 250.198);

(6) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), (incorporated by reference as specified in § 250.198);

(7) API RP 2SK, Recommended Practice for Design and Analysis of Station Keeping Systems for Floating Structures, (incorporated by reference as specified in § 250.198);

(8) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, (incorporated by reference as specified in § 250.198);

(9) API RP 2T, Recommended Practice for Planning, Designing and Constructing Tension Leg Platforms, (incorporated by reference as specified in § 250.198);

(10) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, (incorporated by reference as specified in § 250.198);

(11) American Society for Testing and Materials (ASTM) Standard C 33–99a, Standard Specification for Concrete Aggregates, (incorporated by reference as specified in § 250.198);

(12) ASTM Standard C 94/C 94M–99, Standard Specification for Ready-Mixed Concrete, (incorporated by reference as specified in § 250.198);

(13) ASTM Standard C 150–99, Standard Specification for Portland Cement, (incorporated by reference as specified in § 250.198);

(14) ASTM Standard C 330–99, Standard Specification for Lightweight Aggregates for Structural Concrete, (incorporated by reference as specified in § 250.198);

(15) ASTM Standard C 595–98, Standard Specification for Blended Hydraulic Cements, (incorporated by reference as specified in § 250.198);

(16) AWS D1.1, Structural Welding Code—Steel, including Commentary, (incorporated by reference as specified in § 250.198);

(17) AWS D1.4, Structural Welding Code—Reinforcing Steel, (incorporated by reference as specified in § 250.198);

(18) AWS D3.6M, Specification for Underwater Welding, (incorporated by reference as specified in § 250.198);

(19) NACE Standard MR0175, Sulfide Stress Cracking Resistant Metallic Materials for Oilfield Equipment, (incorporated by reference as specified in § 250.198);

(20) NACE Standard RP 01–76–94, Standard RP, Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production, (incorporated by reference as specified in § 250.198).

(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.

(c) For information on the standards mentioned in this section, and where they may be obtained, see § 250.198 of this part.

(d) The following chart summarizes the applicability of the industry standards listed in this section for fixed and floating platforms:

Industry standard	Applicable to . . .
ACI Standard 318, Building Code Requirements for Reinforced Concrete, Plus Commentary;	Fixed and floating platform, as appropriate.

Industry standard	Applicable to . . .
AISC Standard Specification for Structural Steel Buildings, Allowable Stress Design and Plastic Design;.	
ASTM Standard C33–99a, Standard Specification for Concrete Aggregates;.	
ASTM Standard C94/C94M–99, Standard Specification for Ready-Mixed Concrete;.	
ASTM Standard C150–99, Standard Specification for Portland Cement;.	
ASTM Standard C330–99, Standard Specification for Lightweight Aggregates for Structural Concrete;.	
ASTM Standard C 595–98, Standard Specification for Blended Hydraulic Cements;.	
AWS D1.1, Structural Welding Code—Steel;.	
AWS D1.4, Structural Welding Code—Reinforcing Steel;.	
AWS D3.6M, Specification for Underwater Welding;.	
NACE Standard RP 01–76–94, Standard Recommended Practice (RP), Corrosion Control of Steel Fixed Offshore Platforms Associated with Petroleum Production;.	
API RP 2A—WSD, RP for Planning, Designing, and Constructing Fixed Offshore Platforms—Working Stress Design;.	
ACI357R, Guide for the Design and Construction of Fixed Offshore Concrete Structures;	Fixed platforms.
API RP 14J, RP for Design and Hazards Analysis for Offshore Production Facilities;	Floating platforms.
API RP 2FPS, RP for Planning, Designing, and Constructing, Floating Production Systems;.	
API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs);.	
API RP 2SK, RP for Design and Analysis of Station Keeping Systems for Floating Structures;.	
API RP 2T, RP for Planning, Designing, and Constructing Tension Leg Platforms;.	
API RP 2SM, RP for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring.	

§ 250.902 What are the requirements for 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.

§ 250.903 What records must I keep?

(a) You must compile, retain, and make available to MMS representatives for the functional life of all platforms:

(1) The as-built drawings;

(2) The design assumptions and analyses;

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

(4) The inspection results from the inspections required by § 250.919 of this subpart; and

(5) Records of repairs not covered in the inspection report submitted under § 250.919(b).

(b) You must record and retain the original material test results of all primary structural materials during all stages of construction. Primary material is material that, should it fail, 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).

(c) You must provide MMS with the location of these records in the certification statement of your application for platform approval as required in § 250.905(j).

Platform Approval Program

§ 250.904 What is the Platform Approval Program?

(a) The Platform Approval Program is the MMS basic approval process for platforms on the OCS. The requirements of the Platform Approval Program are described in §§ 250.904 through 250.908 of this subpart. Completing these requirements will satisfy MMS criteria for approval of fixed platforms of a proven design that will be placed in the shallow water areas (≤ 400 ft.) of the Gulf of Mexico OCS.

(b) The requirements of the Platform Approval Program must be met by all platforms on the OCS. Additionally, if you want approval for a floating platform; a platform of unique design; or a platform being installed in deepwater (> 400 ft.) or a frontier area, you must also meet the requirements of the Platform Verification Program. The requirements of the Platform Verification Program are described in §§ 250.909 through 250.918 of this subpart.

§ 250.905 How do I get approval for the installation, modification, or repair of my platform?

The Platform Approval Program requires that you submit the environmental and structural information in the following table for your proposed project.

Required documents	Required contents	Other requirements
(a) Application cover letter	Proposed structure designation, lease number, area, name, and block number, and the type of facility your facility (*e.g.*, drilling, production, quarters). The structure designation must be unique for the field (some fields are made up of several blocks); *i.e.* once a platform "A" has been used in the field there should never be another platform "A" even if the old platform "A" has been removed. Single well free standing caissons should be given the same designation as the well. All other structures are to be designated by letter designations.	You must submit three copies. If, your facility is subject to the Platform Verficiation Program (PVP), you must submit four 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 the nearest block lines. These coordinates must be based on the NAD (North American Datum) 27 datum plane coordinate system.	Your plat must be drawn to a scale of 1 inch equals 2,000 feet and include the coordinates of the lease block boundary lines. You must submit three

Required documents	Required contents	Other requirements
(c) Front, Side, and Plan View drawings.	Platform dimensions and orientation, elevations relative to M.L.L.W. (Mean Lower Low Water), and pile sizes and penetration.	Your drawing sizes must not exceed 11″ × 17″. You must submit three copies (four copies for PVP applications).
(d) Complete set of structural drawings.	The approved for construction fabrication drawings should be submitted including; *e.g.* cathodic protection systems; jacket design; pile foundations; drilling, production, and pipeline risers and riser tensioning systems; turrets and turret-and-hull interfaces; mooring and tethering systems; foundations and anchoring systems.	Your drawing sizes must not exceed 11″ × 17″. You must submit one copy.
(e) Summary of environmental data.	A summary of the environmental data described in the applicable standards referenced under § 250.901(a) of this subpart and in § 250.198 of Subpart A, 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 engineering design data.	Loading information (*e.g.*, live, dead, environmental), structural information (*e.g.*, design-life; material types; cathodic protection systems; design criteria; fatigue life; jacket design; deck design; production component design; pile foundations; drilling, production, and pipeline risers and riser tensioning systems; turrets and turret-and-hull interfaces; foundations, foundation pilings and templates, and anchoring systems; mooring or tethering systems; fabrication and installation guidelines), and foundation information (*e.g.*, soil stability, design criteria).	You must submit one copy.
(g) Project-specific studies used in the platform design or installation.	All studies pertinent to platform design or installation, *e.g.*, oceanographic and/or soil reports including the overall site investigative report required in section 250.906.	You must submit one copy of each study.
(h) Description of the loads imposed on the facility.	Loads imposed by jacket; decks; production components; drilling, production, and pipeline risers, and riser tensioning systems; turrets and turret-and-hull interfaces; foundations, foundation pilings and templates, and anchoring systems; and mooring or tethering systems.	You must submit one copy.
(i) A copy of the in-service inspection plan.	This plan is described in § 250.919.	You must submit one copy.
(j) Certification statement	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, or a naval architect or marine 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 representative must sign the statement. You must submit one copy.

§ 250.906 What must I do to obtain approval for the proposed site of my platform?

(a) *Shallow hazards surveys.* You must perform a high-resolution or acoustic-profiling survey to obtain information on the conditions existing at and near the surface of the seafloor. You must collect information through this survey sufficient to determine the presence of the following features and their likely effects on your proposed platform:

(1) Shallow faults;

(2) Gas seeps or shallow gas;

(3) Slump blocks or slump sediments;

(4) Shallow water flows;

(5) Hydrates; or

(6) Ice scour of seafloor sediments.

(b) *Geologic surveys.* You must perform a geological survey relevant to the design and siting of your platform. Your geological survey must assess:

(1) Seismic activity at your proposed site;

(2) Fault zones, the extent and geometry of faulting, and attenuation effects of geologic conditions near your site; and

(3) For platforms located in producing areas, the possibility and effects of seafloor subsidence.

(c) *Subsurface surveys.* Depending upon the design and location of your proposed platform and the results of the shallow hazard and geologic surveys, the Regional Supervisor may require you to perform a subsurface survey. This survey will include a testing program for investigating the stratigraphic and engineering properties of the soil that may affect the foundations or anchoring systems for your facility. The testing program must include adequate in situ testing, boring, and sampling to examine all important soil and rock strata to determine its strength classification, deformation properties, and dynamic characteristics. If required to perform a subsurface survey, you must prepare and submit to the Regional Supervisor a summary report to briefly describe the results of your soil testing program, the various field and laboratory test methods employed, and the applicability of these methods as they pertain to the quality of the samples, the type of soil, and the anticipated design application. You must explain how the engineering properties of each soil stratum affect the design of your platform. In your explanation you must describe the uncertainties inherent in your overall testing program, and the reliability and applicability of each test method.

(d) *Overall site investigation report.* You must prepare and submit to the Regional Supervisor an overall site investigation report for your platform that integrates the findings of your shallow hazards surveys and geologic surveys, and, if required, your subsurface surveys. Your overall site investigation report must include analyses of the potential for:

(1) Scouring of the seafloor;

(2) Hydraulic instability;

(3) The occurrence of sand waves;

(4) Instability of slopes at the platform location;

(5) Liquifaction, or possible reduction of soil strength due to increased pore pressures;

(6) Degradation of subsea permafrost layers;

(7) Cyclic loading;

(8) Lateral loading;

(9) Dynamic loading;

(10) Settlements and displacements;

(11) Plastic deformation and formation collapse mechanisms; and

(12) Soil reactions on the platform foundations or anchoring systems.

§ 250.907 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.

§ 250.908 What are the minimum structural fatigue design requirements?

(a) API RP 2A-WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms (incorporated by reference as specified in 30 CFR 250.198), requires that the design fatigue life of each joint and member be twice the intended service life of the structure. When designing your platform, the following table provides minimum fatigue life safety factors for critical structural members and joints.

If . . .	Then . . .
(1) There is sufficient structural redundancy to prevent catastrophic failure of the platform or structure under consideration.	The results of the analysis must indicate a maximum calculated life of twice the design life of the platform.
(2) There is not sufficient structural redundancy to prevent catastrophic failure of the platform or structure.	The results of a fatigue analysis must indicate a minimum calculated life or three times the design life of the platform.
(3) 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.

(b) The documents incorporated by reference in § 250.901 may require larger safety factors than indicated in paragraph (a) of this section for some key components. When the documents incorporated by reference require a larger safety factor than the chart in paragraph (a) of this section, the requirements of the incorporated document will prevail.

Platform Verification Program

§ 250.909 What is the Platform Verification Program?

The Platform Verification Program is the MMS approval process for ensuring that floating platforms; platforms of a new or unique design; platforms in seismic areas; or platforms located in deepwater or frontier areas meet stringent requirements for design and construction. The program is applied during construction of new platforms and major modifications of, or repairs to, existing platforms. These requirements are in addition to the requirements of the Platform Approval Program described in §§ 250.904 through 250.908 of this subpart.

§ 250.910 Which of my facilities 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 to the extent indicated in the following table:

If . . .	Then . . .
(1) Your new floating platform is a buoyant offshore facility that does not have a ship-shaped hull.	The entire platform is subject to the Platform Verification Program including the following associated structures: (i) Drilling, production, and pipeline risers, and riser tensioning systems (each platform must be designed to accommodate all the loads imposed by all risers and riser does not have tensioning systems); (ii) Turrets and turret-and-hull interfaces; (iii) Foundations, foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.
(2) Your new floating platform is a buoyant offshore facility with a ship-shaped hull.	Only the following structures that may be associated with a floating platform are subject to the Platform Verification Program: (i) Drilling, production, and pipeline risers, and riser tensioning systems (each platform must be designed to accommodate all the loads imposed by all risers and riser a ship-shaped tensioning systems); (ii) Turrets and turret-and-hull interfaces; (iii) Foundations, foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.

(c) If a platform is originally subject to the Platform Verification Program, then the conversion of that platform at that same site for a new purpose, or making a major modification of, or major repair to, that platform, is also subject to the Platform Verification Program. A major modification includes any modification that increases loading on a platform by 10 percent or more. A major repair is a corrective operation involving structural members affecting the structural integrity of a portion or all of the platform. Before you make a major modification or repair to a floating platform, you must obtain approval from both the MMS and the USCG.

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

§ 250.911 If my platform is subject to the Platform Verification Program, what must I do?

If your platform, conversion, or major modification or repair meets the criteria in § 250.910, you must:

(a) Design, fabricate, install, use, maintain and inspect your platform, conversion, or major modification or repair to your platform according to the requirements of this subpart, and the applicable documents listed in § 250.901(a) of this subpart;

(b) Comply with all the requirements of the Platform Approval Program found in §§ 250.904 through 250.908 of this subpart.

(c) Submit for the Regional Supervisor's approval three copies each of the design verification, fabrication verification, and installation verification plans required by § 250.912;

(d) Include your nomination of a Certified Verification Agent (CVA) as a part of each verification plan required by § 250.912;

(e) Follow the additional requirements in §§ 250.913 through 250.918;

(f) Obtain approval for modifications to approved plans and for major deviations from approved installation procedures from the Regional Supervisor; and

(g) Comply with applicable USCG regulations for floating OCS facilities.

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

If your platform, associated structure, or major modification meets the criteria in § 250.910, you must submit the following plans to the Regional Supervisor for approval:

(a) *Design verification plan.* You may submit your design verification plan with or subsequent to the submittal of your Development and Production Plan (DPP) or Development Operations Coordination Document (DOCD). Your design verification must be conducted by, or be under the direct supervision of, a registered professional civil or structural engineer or equivalent, or a naval architect or marine engineer or equivalent, with previous experience in directing the design of similar facilities, systems, structures, or equipment. For floating platforms, you must ensure that the requirements of the USCG for structural integrity and stability, *e.g.*, verification of center of gravity, etc., have been met. Your design verification plan must include the following:

(1) All design documentation specified in § 250.905 of this subpart;

(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.* 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-gravity 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.* 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) An identification of the areas to be inspected. You must specify the acceptance and rejection criteria to be used for any inspections conducted during installation, and for the post-installation verification inspection.

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

§ 250.913 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.

§ 250.914 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, or for any combination of these phases.

(b) For each CVA, you must submit a list of documents to be forwarded to the CVA, and a qualification statement that includes the following:

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

(2) Technical capabilities of the individual or the primary staff for the specific project;

(3) Size and type of organization or corporation;

(4) In-house availability of, or access to, appropriate technology. This should include computer programs, 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.

§ 250.915 What are the CVA's primary responsibilities?

(a) The CVA must conduct specified reviews according to §§ 250.916, 250.917, and 250.918 of this subpart.

(b) Individuals or organizations acting as CVAs must not function in any capacity that would create a conflict of interest, or the appearance of a conflict of interest.

(c) The CVA must consider the applicable provisions of the documents listed in § 250.901(a); the alternative codes, rules, and standards approved under 250.901(b); and the requirements of this subpart.

(d) The CVA is the primary contact with the Regional Supervisor and is directly responsible for providing immediate reports of all incidents that affect the design, fabrication and installation of the platform.

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

(a) The CVA must use good engineering judgement and practices in conducting an independent assessment of the design of the platform, major modification, or repair. The CVA must ensure that the platform, major modification, or repair is designed to withstand the environmental and functional load conditions appropriate for the intended service life at the proposed location.

(b) Primary duties of the CVA during the design phase include the following:

Type of facility . . .	The CVA must . . .
(1) For fixed platforms and non-ship-shaped floating facilities	Conduct an independent assessment of all proposed: (i) Planning criteria; (ii) Operational requirements; (iii) Environmental loading data; (iv) Load determinations; (v) Stress analyses; (vi) Material designations; (vii) Soil and foundation conditions; (viii) Safety factors; and (ix) Other pertinent parameters of the proposed design.
(2)For all floating facilities	Ensure that the requirements of the U.S. Coast Guard for structural integrity and stability, *e.g.*, verification of center of gravity, etc., have been met. The CVA must also consider: (i) Drilling, production, and pipeline risers, and riser tensioning systems; (ii) Turrets and turret-and-hull interfaces; (iii) Foundations, foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.

(c) The CVA must submit interim reports to the Regional Supervisor and to you, as appropriate. The CVA, upon completion of the design verification, must prepare a final report and submit one copy to the Regional Supervisor. The CVA must submit the final report within 90 days of the receipt of the design data, or within 90 days from the date the approval to act as a CVA was issued, whichever is later. The CVA must submit the final report to the Regional Supervisor before fabrication begins, and must include:

(1) A summary of the material reviewed and the CVA's findings;

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

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

(4) Any additional comments the CVA may deem necessary.

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

(a) The CVA must use good engineering judgement and practices in conducting an independent assessment of the fabrication activities. The CVA must monitor the fabrication of the platform or major modification to ensure that it has been built according to the approved design and the fabrication plan. 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.

(b) Primary duties of the CVA during the fabrication phase include the following:

Type of facility . . .	The CVA must . . .
(1) For all fixed platforms and non-ship-shaped floating facilities	Make periodic onsite inspections while fabrication is in progress and must verify the following fabrication items, as appropriate: (i) Quality control by lessee and builder; (ii) Fabrication site facilities; (iii) Material quality and identification methods; (iv) Fabrication procedures specified in the approved plan, and adherence to such procedures; (v) Welder and welding procedure qualification and identification; (vi) Structural tolerences specified and adherence to those tolerances; (vii) The nondestructive examination requirements, and evaluation results of the specified examinations; (viii) Destructive testing requirements and results; (ix) Repair procedures; (x) Installation of corrosion-protection systems and splash-zone protection; (xi) Erection procedures to ensure that overstressing of structural members does not occur; (xii) Alignment procedures; (xiii) Dimensional check of the overall structure, including any turrets, turret-and-hull interfaces, any mooring line and chain and riser tensioning line segments; and (xiv) Status of quality-control records at various stages of fabrication.

Type of facility . . .	The CVA must . . .
(2) For all floating facilities	Ensure that the requirements of the U.S. Coast Guard floating for structural integrity and stability, *e.g.*, verification of center of gravity, etc., have been met. The CVA must also consider: (i) Drilling, production, and pipeline risers, and riser tensioning systems (at least for the initial fabrication of these elements); (ii) Turrets and turret-and-hull interfaces; (iii) Foundation pilings and templates, and anchoring systems; and (iv) Mooring or tethering systems.

(c) *Reports.* The CVA must submit interim reports to the Regional Supervisor and to you, as appropriate. The CVA must prepare a final report covering the adequacy of the entire fabrication phase. The final report need not cover aspects of the fabrication already included in interim reports. The CVA must submit one copy of the final report to the Regional Supervisor within 90 days after completion of the fabrication phase but before the beginning of the installation phase. In the final report the CVA must:

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

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

(3) Summarize the CVA's findings;

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

(5) Make a recommendation to accept or reject the fabrication; and

(6) Provide any additional comments that the CVA deems necessary.

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

(a) The CVA must use good engineering judgment and practice in conducting an independent assessment of the installation activities.

(b) Primary duties of the CVA during the installation phase include the following:

The CVA must . . .	Operation or equipment to be inspected . . .
(1) Verify, as appropriate	(i) Loadout and initial flotation operations; (ii) Towing operations to the specified location, and review the towing records; (iii) Launching and uprighting operations; (iv) Submergence operations; (v) Pile or anchor installations; (vi) Installation of mooring and tethering systems; (vii) Final deck and component installations; and (viii) Installation at the approved location according to the approved design and the installation plan.
(2) Witness (for a fixed or floating platform)	(i) The loadout of the jacket, decks, piles, or structures from each fabrication site; (ii) The actual installation of the platform or major modification and the related installation activities.
(3) Witness (for a floating platform)	(i) The loadout of the platform; (ii) The installation of drilling, production, and pipeline risers, and riser tensioning systems (at least for the initial installation of these elements); (iii) The installation of turrets and turret-and-hull interfaces; (iv) The installation of foundation pilings and templates, and anchoring systems; and (v) The installation of the mooring and tethering systems.
(4) Conduct an onsite survey	Survey the platform after transportation to the approved location.
(5) Spot-check as necessary to determine compliance with the applicable documents listed in § 250.901(a); the alternative codes, rules and standards approved under 250.901(b); the requirements listed in § 250.903 and § 250.906 through 250.908 of this subpart and the approved plans.	(i) Equipment; (ii) Procedures; and (iii) Recordkeeping.

(c) *Reports.* The CVA must submit interim reports to you and the Regional Supervisor, as appropriate. 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 30 days of the installation of the platform. In the final report, the CVA must:

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

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

(3) Summarize the CVA's findings;

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

(5) Provide a recommendation to accept or reject the installation; and

(6) Provide any additional comments that the CVA deems necessary.

Inspection, Maintenance, and Assessment of Platforms

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

(a) You must develop a comprehensive annual in-service inspection plan covering all of your platforms. As a minimum, your plan must address the recommendations of the appropriate documents listed in § 250.901(a). Your plan must specify the type, extent, and frequency of in-place inspections which you will conduct for both the above water and the below water structure of all platforms, and pertinent components of the mooring systems for floating platforms. The plan must also address how you are monitoring the corrosion protection for both the above water and below water structure.

(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.

§ 250.920 What are the MMS requirements for assessment of platforms?

(a) You must perform a platform assessment when needed, based on the platform assessment initiators listed in sections 17.2.1–17.2.5 of API RP 2A–WSD, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms—Working Stress Design (incorporated by reference as specified in 30 CFR 250.198).

(b) You must initiate mitigation actions for platforms that do not pass the assessment process of API RP 2A–WSD.

(c) You must document all wells, equipment, and pipelines supported by the platform if you intend to use the medium or low consequence of failure exposure category for your assessment. Exposure categories are defined in API RP 2A–WSD Section 1.7.

(d) MMS may require you to conduct a platform assessment where reduced environmental loading criteria are not allowed.

(e) The use of Section 17, Assessment of Existing Platforms, of API RP 2A–WSD, is limited to existing fixed structures that are serving their original approved purpose.

§ 250.921 How do I analyze my platform for cumulative fatigue?

(a) If you are required to analyze cumulative fatigue on your platform because of the results of an inspection or platform assessment, you must ensure that the safety factors for critical elements listed in § 250.908 are met or exceeded.

(b) If the calculated life of a joint or member does not meet the criteria of § 250.908, you must either mitigate the load, strengthen the joint or member, or develop an increased inspection process.

■ 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, you must design them according to the standards and procedures of API Spec 17J, incorporated by reference as specified in 30 CFR 250.198.

(5) You must design pipeline risers for tension leg platforms and other floating platforms according to the design standards of API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension Leg Platforms (TLPs), incorporated by reference as specified in 30 CFR 250.198.

* * * * *

9. In § 250.1007, revise paragraph (a)(4) to read as follows:

§ 250.1007 What to include in applications.

(a) * * *

(4) The application must include a description of any additional design precautions which were taken to enable the pipeline to withstand the effects of water currents, storm or ice scouring, soft bottoms, mudslides, earthquakes, permafrost, and other environmental factors. If your application involves using unbonded flexible pipe, you must:

(i) Review the manufacturer's Design Methodology Verification Report, and the independent verification agent's (IVA's) certificate for the design methodology contained in that report, to ensure that the manufacturer has complied with the requirements of API Spec 17J incorporated by reference as specified in 30 CFR 250.198;

(ii) Determine that the unbonded flexible pipe is suitable for its intended purpose on the lease or pipeline right-of-way;

(iii) Submit to the MMS Regional Supervisor the manufacturer's design specifications for the unbonded flexible pipe; and

(iv) Submit to the MMS Regional Supervisor a statement certifying that the pipe is suitable for its intended use, and that the manufacturer has complied with the IVA requirements of API Spec 17J incorporated by reference as specified in 30 CFR 250.198.

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