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Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
Preamble, p.45	Lifecycle analysis approach to other types of critical equipment such as blowout preventers (BOPs) The BSEE is considering applying a lifecycle analysis approach to other types of critical equipment that we regulate. We are specifically requesting comments on how this approach could be used to assist in increasing the reliability of critical equipment such as BOPs. The BSEE currently relies on pressure testing to demonstrate BOP performance and reliability. Can a lifecycle approach replace or supplement these requirements? Are there other types of critical equipment that are good candidates for the life cycle approach? Are there industry standards that can serve as the basis for BSEE's increased focus on the life cycle of critical equipment?	OOC would recommend that BSEE clarify what is meant by "lifecycle approach". We would encourage and fully support a formal dialogue with BSEE to look at alternative approaches. In this proposed rule, BSEE has appropriately referenced a number of standards that include design, materials, fabrication, and verification. Other standards exist to address integrity management and fitness for service that would be worth examining to assist in increasing reliability of safety critical equipment.	
Preamble, p.46	Failure reporting and information dissemination The BSEE requests comments on whether these failure reports should be submitted directly to BSEE or provided to an appropriate third party organization that would be responsible for reviewing and analyzing the data and notifying the industry of potential problems. The BSEE also requests comments on how this type of system could be broadened to include international offshore operations.	OOC would recommend neither of these options. Communications with the manufacturer, as is required in several API documents incorporated by reference, is the best mechanism to identify root cause of significant failures. If a significant failure occurs where a recall by the manufacturer is warranted, BSEE or a third party such as OESI could be a recipient of these reports to aid in communication with all of industry. Currently, requirements for failure reporting apply to SSVs, USVs and SSSVs covered in this subpart. OOC suggests that this is appropriate and adequate for this subpart. If BSEE is considering this type of process for other safety critical technologies, OOC would recommend that BSEE suggest language through proposed rulemaking through the applicable subpart.	
Preamble, p.46	Third party certification organizations The BSEE solicits comments on the use of third party certification organizations to assist BSEE in ensuring that these systems are designed and maintained during its entire service	OOC does not support the blanket us of third party certification organizations. BSEE mandated the use of third party auditors in its Subpart S rulemaking, but has since recognized that these organizations do not necessarily have technical expertise needed to perform these functions. BSEE	

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	life with an acceptable degree of risk.	should focus on established standards and performance-based requirements.	
Preamble, p.47	Limiting Emissions of Natural Gas from OCS Production Equipment The BSEE is evaluating opportunities to reduce methane and other air emissions through use of the best available production equipment technology and practices. We are seeking additional information on these opportunities. Information obtained through public comments on this topic may be used to support a Regulatory Impact Analysis. We are not proposing new production equipment requirements to limit emissions in this rulemaking, but are seeking additional information on technologies and costs for emissions-limiting equipment that can be used on OCS production facilities.	OOC has previously provided detailed information to BOEM on this issue and would welcome additional dialogue with the agency.	
Comments on Proposed Rule			
250.105	Definitions -	Revise definition from "technology' to 'technologies' for consistency with OCSLA to clarify that BAST constitutes multiple economically feasible technology options.	Recommended language to read: “Best available and safest technologies (BAST) means the best available and safest technologies that the BSEE Director determines to be economically feasible wherever failure of equipment would have a significant effect on safety, health, or the environment.”
250.107(c)(1)	(c)(1) Wherever failure of equipment may have a significant effect on safety, health, or the environment, you must use the best available and safest technology (BAST) that BSEE determines to be economically feasible on:	OOC submitted comments on this revision in our joint industry letter dated October 16, 2013. The agency has previously recognized that technologies in place are BAST. Our proposed language recognizes that existing technologies meet the intent of OCSLA. Please note that OOC sees no reason for removing the language in the existing BAST regulations as it does not preclude BSEE from making additional determinations, and is consistent with OCSLA.	OOC recommends that BSEE more closely align with OCS Lands Act and Congressional intent; and recommends revising the language to read: "(c) BSEE shall require, on all new drilling and production operations, the use of the best available and safest technologies which BSEE determines to be economically feasible, wherever failure of equipment would have a significant effect on safety, health, or the environment, except where BSEE determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing

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			such technologies. (d) When failures occur with existing technologies that have previously been determined to be BAST, BSEE may require additional technologies after: (1) BSEE has determined that the failure would have a significant effect on safety, health or environment; and (2) BSEE has evaluated existing technologies and determined the use of these technologies are no longer BAST for the specific application; and (3) BSEE has determined there are alternative BAST technologies that are economically feasible; and (4) BSEE has determined incremental benefits clearly justify the incremental costs of utilizing such technologies. (e) You may request an exception by demonstrating to BSEE that the incremental benefits of using BAST are clearly insufficient to justify the incremental costs of utilizing such technologies."
250.800 (b)	<u>General.</u> For all new production systems on fixed leg platforms, you must comply with API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities (incorporated by reference as specified in § 250.198);	RP 14J is a guidance document that identifies multiple tools for conducting a hazards analysis on offshore facilities. The directive "must comply with RP 14J" is vague in that it does not identify specifically what the operator is to do to meet BSEE's expectation(s). Further, an operator is ALREADY required to conduct a hazards analysis using any one of the tools identified in 14J or other recognized document in accordance with 30 CFR 250 Subpart S. OOC recommends that BSEE delete this requirement from this subpart since it is a redundant requirement. Should BSEE choose to ignore this recommendation, OOC then recommends that BSEE revise the language to read, **"For all new production systems on fixed**	

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		leg platforms, you must conduct a hazards analysis utilizing any one of the methodologies identified in API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities (incorporated by reference as specified in § 250.198);"	
250.800 (c)(1)	<u>General</u> (c) 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: (1) Comply with API RP 14J;	RP 14J is a guidance document that identifies multiple tools for conducting a hazards analysis on offshore facilities. The directive "must comply with RP 14J" is vague in that it does not identify specifically what the operator is to do to meet BSEE's expectation(s). Further, an operator is ALREADY required to conduct a hazards analysis using any one of the tools identified in 14J or other recognized document in accordance with 30 CFR 250 Subpart S. OOC recommends that BSEE delete this requirement from this subpart since it is a redundant requirement. Should BSEE choose to ignore this recommendation, OOC then recommends that BSEE revise the language to read, **"(c) 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 conduct a hazards analysis utilizing any one of the methodologies identified in API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities (incorporated by reference as specified in § 250.198);"**	
250.800 (c)(2)	<u>General.</u> Meet the drilling, well completion, well workover, and well production riser standards of API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs) (incorporated by reference as specified in § 250.198). (2) Meet the drilling, well completion, well workover, and well production riser standards of API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems	It is our understanding from discussions with BSEE staff that existing single bore production risers are not affected by this proposed rule. Also that it is BSSE's intent to prohibit use of single bore production risers only and not single bore drilling or pipeline risers. We believe this technology is applicable in some applications and BSEE should still allow for consideration of future use of single bore production risers on a case by case basis. The use of single bore production risers may allow for production of those reservoirs that would otherwise be	OOC recommends that the language be revised to read "(2) Meet the production riser standards of API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs) (incorporated by reference as specified in § 250.198). Beginning 1 year from the publication date of the final rule and thereafter, you are prohibited from installing single bore dry tree top tension production risers from floating production facilities unless you obtain approval for utilization of a single

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	(FPSs) and Tension-Leg Platforms (TLPs) (incorporated by reference as specified in § 250.198). Beginning 1 year from the publication date of the final rule and thereafter, you are prohibited from installing single bore production risers from floating production facilities.	uneconomical. Reserves will remain undeveloped. BSEE should provide justification for prohibition of a technology that has not been proven to be problematic. The Preamble does not support this action. The statement that "BSEE believes that a single bore production riser does not provide an acceptable level of safety to operate on the OCS when an operator has to perform work through the riser" is of great concern. The preamble does not provide any detail on why BSEE believes this situation is unacceptable. At a minimum, BSEE needs to justify why this practice is unacceptable and describe the potential risk that exists on the OCS today - how many facilities have single bore production risers, production rates, lost reserves, activity level of work through these risers, mitigating measures taken to address the unacceptable level of safety, etc. Furthermore, if BSEE believes this practice to be unsafe, why does BSEE allow this practice to be available for up to a year after the publication of the final rule? See Attachment 3 for additional supporting comments and rationale.	bore production riser system via 250.141."
250.801 (a)	<u>Safety and pollution prevention equipment (SPPE) certification.</u> (a) *SPPE equipment.* In wells located on the OCS, you must install only safety and pollution prevention equipment (SPPE) considered certified under paragraph (b) of this section or accepted under paragraph (c) of this section. The BSEE considers the following equipment to be types of SPPE: (1) Surface safety valves (SSV) and actuators, including those installed on injection wells capable of natural flow; (2) Boarding shut down valves (BSDV), 1 year after the date of	With respect to the inclusion of BSDVs, the SWRI report project #272 referenced by BSEE in the proposed rulemaking (250.880, pg. 43) shows a certified valve does not perform any better than a non-certified valve. BSEE has only referenced selected sections from the report that support their case. BSEE has not demonstrated, through statistics and failure data, justification for this requirement. The report states "It has been determined that there is no statistically significant difference in the proportion of failures between certified and non-certified surface safety valves." The requirement for use of only "certified" SPPE is not	

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	publication of the final rule; (3) Underwater safety valves (USV) and actuators; and (4) Subsurface safety valves (SSSV) and associated safety valve locks and landing nipples. Subsurface-controlled SSSVs are not allowed on subsea wells.	supported by the referenced report and will not provide any greater degree of safety or dependability. OOC does support BSEE's efforts to work with industry to increase reliability of BSDVs; however, the requirement for certification will not drive the performance results. Further, OOC supports the use of API standards; however, the agency does not recognize API Spec 6D or other ANSI standards used in this service. Additionally, OOC requests that BSEE clarify BSDVs as in§ 250.835 as only those valves associated with subsea systems. In discussion with BSEE staff, it is the agency's intent to address only BSDVs associated with subsea systems. Should BSEE choose to keep the certification requirement, then OOC requests that BSEE extend the 1-year timeframe to 2 years for compliance. Where no isolation valve exists, replacement would require excessive shutdown time and construction work on lines that have previously contained hydrocarbons, greatly increasing the risk for a serious incident only to arbitrarily replace a valve that cannot be shown to be inferior and in need of replacement.	
250.802 (c)(1)	(1) Each device must be designed to function and to close at the most extreme conditions to which it may be exposed, including temperature, pressure, flow rates, and environmental conditions. You must have an independent third party review and certify that each device will function as designed under the conditions to which it may be exposed. The independent third party must have sufficient expertise and experience to perform the review and certification.	Wording in this section is not derived from the documents incorporated by reference. OOC recommends that inaccurate and conflicting language be removed as this section conflicts with the intended rulemaking. Additionally, as previously commented, BSDVs are not specifically addressed in the referenced standards. Discussions with BSEE HQ staff have clarified that the intent of the "independent third party" (I3P) language was not intended to require more than a certification and marking with the API monogram by the manufacturer. Requiring an individual I3P to "guarantee" functionality of every individual item of equipment would not be achievable. Manufacturers and operators are responsible for appropriate	OOC recommends revising the language to read: "(c) Requirements derived from the documents incorporated in this section for SSVs, BSDVs, USVs, and SSSVs, include, but are not limited to, the following: 1) Each device must be designed to function and to close at the most extreme conditions to which it may be exposed, including temperature, pressure, flow rates, and environmental conditions in accordance with the applicable referenced documents. SPPE must be certified in accordance with the applicable standards and marked with the API monogram in accordance with API Spec Q1, or have documentation

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		manufacture and application of SPPE.	demonstrating certification."
250.802 (c)(6)	Requirements for SPPE. You must follow specified installation, testing, and repair protocols.	Should include reference to API RP 14H.	
250.803(a)	(a) You must follow the failure reporting requirements contained in section 10.20.7.4 of API Spec. 6A for SSVs, BSDVs, and USVs and section 7.10 of API Spec. 14A and Annex F of API RP 14B for SSSVs (all incorporated by reference in § 250.198). You must provide a written report of equipment failure to the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification.	Proposed language is inconsistent with the referenced standards. Given that a failure is defined in sub-paragraph (a) as being "any condition that prevents the equipment from meeting the functional specification" it is likely that a significant number of non-critical failure conditions would need to be investigated, analysed and reported in order to comply with the regulation as currently written. For example, the failure of a valve position indictor device would theoretically require investigation, analysis and reporting to the manufacturer. Furthermore, for equipment such as a subsea tree where a significant level of redundancy is typically included in the system design (e.g. use of 2 or more USVs on the subsea tree, as described in paragraph 250.833 (b)) it will often not be practical, economically feasible or even necessary to retrieve the equipment in order to continue to meet the functional specification for the tree system as a whole, i.e., to still have at least one fully functioning USV. As currently written, the regulation would likely result in a very significant additional burden on operators, suppliers and the BSEE, without delivering equivalent improvements in equipment operation, safety or future reliability. It is therefore strongly recommended that the requirement to investigate, analyse and report SPPE failures be limited to cases which involve a loss of containment, i.e., an unintended release of hydrocarbons to the environment.	Delete BSDVs. Add reference to API RP 14H. OOC recommends that the following be deleted: "You must provide a written report of equipment failure to the manufacturer of such equipment within 30 days after the discovery and identification of the failure. A failure is any condition that prevents the equipment from meeting the functional specification."
250.803(b)	(b) You must ensure that an investigation and a failure analysis are performed within 60 days of the failure to determine the cause of the failure. You must also ensure that the results and	Proposed language is inconsistent with the referenced standards. Root cause failure analysis results will take longer than 60 days to produce. This is even more apparent if	OOC recommends this wording be deleted since the process is described in the referenced documents.

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	any corrective action are documented. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the manufacturer receives a copy of the analysis report.	determining a root cause failure on subsea SPPE. The requirement to provide a written report of equipment failure to the manufacturer within 30 days after the discovery and identification of the failure, and a failure analysis performed within 60 days of the failure to determine the cause of the failure is unrealistic, especially in the case of subsea components or complicated systems. An alternative to this language may be the reporting of the failure (to BSEE and manufacturer) within 30 days and identification / analysis and report of findings within 120 days. Failure analysis would likely require cooperation with the device manufacturer as some data and design information is considered proprietary. Considering device failure without incorporating other data such as service conditions, maintenance records, etc. could result in misleading conclusions as to the reliability of a device. Additional guidance should be provided by BSEE for failures of those devices for which a manufacturer is no longer in business. Failure of this type of device would normally result in replacement with a current model rather than the burden of failure investigation that would not yield a corresponding benefit.	
250.810	For wells using dry trees or for which you intend to install dry trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless, after you submit a request containing a justification, the District Manager determines the well to be incapable of natural flow. These subsurface safety devices include the following devices and any associated safety valve lock, flow coupling above and below, and landing nipple:	Remove flow couplings from all sections requiring certification of such - it is not a safety device. They are merely heavy-walled couplings used where turbulent flow may be present. Additionally, OOC recommends that BSEE incorporate by reference, API Spec 14L (Specification for Lock Mandrels and Landing Nipples, (most recent edition).	OOC recommends revising the language to read: "These subsurface safety devices include the following devices and any associated safety valve lock and landing nipples."
250.811	All surface-controlled and subsurface-controlled SSSVs, safety valve locks, landing nipples, and flow couplings installed in the OCS must conform to the requirements in §§ 250.801 through	This language indicates that "flow couplings" must conform to the SPPE requirements; however, there are no API or industry standards for flow couplings as they are a manufacturer	OOC recommends removal of the reference to flow couplings and revise the language to read:

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	250.803. You may request that BSEE approve non-conforming SSSVs in accordance with § 250.141, regarding alternative procedures or equipment.	specific item of equipment. Also, flow couplings are not identified as SPPE in 801-803. Further flow couplings are not safety devices. They are merely heavy-walled couplings used in conjunction with some down-hole safety device applications.	"All surface-controlled and subsurface-controlled SSSVs, safety valve locks, and landing nipples installed in the OCS must conform to the requirements in §§ 250.801 through 250.803.
§ 250.813	<u>Subsurface-controlled SSSVs.</u> You may request BSEE approval to equip a dry tree well with a subsurface-controlled SSSV in lieu of a surface-controlled SSSV, in accordance with § 250.141 regarding alternative procedures or equipment, if the subsurface-controlled SSSV installed in a well equipped with a surface-controlled SSSV has become inoperable and cannot be repaired without removal and reinstallation of the tubing. If you remove and reinstall the tubing, you must equip the well with a surface-controlled SSSV.	There appears to be a grammatical error in this requirement making the proposed language confusing.	OOC recommends correcting the error for the language to read: "You may request BSEE approval to equip a dry tree well with a subsurface-controlled SSSV in lieu of a surface-controlled SSSV, in accordance with § 250.141 regarding alternative procedures or equipment, if the subsurface-controlled SSSV **is** installed in a well equipped with a surface-controlled SSSV **that** has become inoperable and cannot be repaired without removal and reinstallation of the tubing. If you remove and reinstall the tubing, you must equip the well with a surface-controlled SSSV.
250.817 (c)	<u>§ 250.817 Temporary removal of subsurface safety devices for routine operations.</u> (c) You must monitor a platform well when a subsurface safety device has been removed, but a person does not need to remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended with a support vessel or a pump-through plug installed in the tubing at least 100 feet below the mudline, and the master valve must be closed, unless otherwise approved by the appropriate District Manager.	This is a new requirement to have a support vessel in attendance if a SCSSV is inoperable. It's not clear what the purpose of the support vessel would be.	Recommend revising language to read: "(c) You must monitor a platform well when a subsurface safety device has been removed, but a person does not need to remain in the well-bay area continuously if the master valve is closed. If the well is on a satellite structure, it must be attended or a pump-through plug installed in the tubing at least 100 feet below the mudline, and the master valve must be closed, unless otherwise approved by the appropriate District Manager."
250.821	<u>250.821 Emergency Action</u> (a) In the event of an emergency, such as an impending named tropical storm or hurricane: (1) Any well not yet equipped with a subsurface safety device and that is capable of natural flow must have the subsurface	The term "impending named tropical storm or hurricane" needs to be better defined. There are some cases where named storms do not necessarily require shutting in. If the term is meant only as an example of an emergency and not meant to be all-inclusive, then recommend the wording to be	OOC recommends revising the title of this section and the language to read as follows: <u>250.821 - Tropical Storm/Hurricane Action</u> (a) In the event of an emergency, such as an impending

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	safety device properly installed as soon as possible, with due consideration being given to personnel safety. (2) You must shut-in all oil wells and gas wells requiring compression, unless otherwise approved by the District Manager in accordance with §§ 250.141 or 250.142. The shut-in may be accomplished by closing the SSV and SSSV. (b) Closure of the SSV must not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV must close within 2 minutes after the shut-in signal has closed the SSV. The District Manager must approve any design-delayed closure time greater than 2 minutes based on the mechanical/production characteristics of the individual well or subsea field in accordance with §§ 250.141 or 250.142.	clarified. The reference in the last sentence of 250.821(b) to a subsea field does not belong in this section, as this section pertains specifically to dry tree wells only. Also, the title indicates emergency action, however, the only examples given reference tropical storms and hurricanes.	named tropical storm or hurricane, which would approach an active lease, in such a way that initiates implementation of the Lessee's Hurricane Preparedness/Evacuation Plan: (1) Any well not yet equipped with a subsurface safety device, such as temporary removal for routine operations, described in 250.817(a), and that is capable of natural flow must have the subsurface safety device properly installed as soon as possible, with due consideration being given to personnel safety. (2) You must shut-in all oil wells and gas wells requiring compression, unless otherwise approved by the District Manager in accordance with 250.141 or 250.142 or an approved SCADA plan.
250.821(b)	(b) Closure of the SSV must not exceed 45 seconds after automatic detection of an abnormal condition or actuation of an ESD. The surface-controlled SSSV must close within 2 minutes after the shut-in signal has closed the SSV. The District Manager must approve any design-delayed closure time greater than 2 minutes based on the mechanical/production characteristics of the individual well or subsea field in accordance with §§ 250.141 or 250.142.	This language is specific to dry tree SSVs, however, "subsea field" is mentioned. OOC recommends deleting the reference to "subsea field" so that the language reads:	"The District Manager must approve any design-delayed closure time greater than 2 minutes based on the mechanical/production characteristics of the individual well in accordance with §§ 250.141 or 250.142."
250.825 (a)	<u>Subsea tree subsurface safety devices – general.</u> For wells using subsea (wet) trees or for which you intend to install subsea trees, you must equip all tubing installations open to hydrocarbon-bearing zones with subsurface safety devices that will shut off the flow from the well in the event of an emergency unless. You may seek BSEE approval for using alternative procedures or equipment in accordance with § 250.141 if you propose to use a subsea safety system that is not capable of shutting off the flow from the well in the event of an emergency, for	This language indicates that "flow couplings" must conform to the SPPE requirements; however, there are no API or industry standards for flow couplings as they are a manufacturer specific item of equipment. Also, flow couplings are not identified as SPPE in 801-803. Further flow couplings are not safety devices. They are merely heavy-walled couplings used in conjunction with some down-hole safety device applications.	OOC recommends removal of the reference to flow couplings and revise the language to read: "Subsurface safety devices include the following and any associated safety valve lock, and landing nipple."

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	instance where the well at issue is incapable of natural flow. Subsurface safety devices include the following and any associated safety valve lock, flow coupling above and below, and landing nipple: (1) A surface-controlled SSSV; (2) An injection valve; (3) A tubing plug; and (4) A tubing/annular subsurface safety device.		
250.826	All SSSVs, safety valve locks, flow couplings, and landing nipples must conform to the requirements specified in §§ 250.801 through 250.803 and any Deepwater Operations Plan (DWOP) required by §§ 250.286 through 250.295.	This language indicates that "flow couplings" must conform to the SPPE requirements; however, there are no API or industry standards for flow couplings as they are a manufacturer specific item of equipment. Also, flow couplings are not identified as SPPE in 801-803. Further flow couplings are not safety devices. They are merely heavy-walled couplings used in conjunction with some down-hole safety device applications.	OOC recommends revising the language to read: "All SSSVs, safety valve locks and landing nipples must conform to the requirements specified in §§ 250.801 through 250.803 and any Deepwater Operations Plan (DWOP) required by §§ 250.286 through 250.295."
250.827	Surface-controlled SSSVs – subsea trees. The surface controls must be located on the site, or you may seek BSEE approval for locating the controls at a remote location in a request to use alternative procedures or equipment under § 250.141.	It is not clear how this requirement is to be interpreted with respect to subsea wells. Does the use of a Subsea Control Module on/immediately adjacent to a subsea tree qualify as having the "surface controls…located on the site"?	OOC recommends revising the language to read: "All tubing installations open to a hydrocarbon-bearing zone that is capable of natural flow must be equipped with a surface-controlled SSSV, except as specified in §§ 250.829 and 250.830. The surface controls must be located on the host site. BSEE approval for locating the controls other than the host site is required."
250.828 (b)	Design, installation, and operation of SSSVs – subsea trees. The well must not be open to flow while an SCSSV is inoperable.	BSEE should add wording similar to surface trees that allows temporary flow for routine operations / well troubleshooting.	OOC recommends revising the language to read: "The well must not be open to flow while an SSSV is inoperable once the subsea tree is installed or BSEE has approved the specific operation that requires flow with an inoperable SSSV."
250.828 (c)	Design, installation, and operation of SSSVs – subsea trees. You must install, maintain, inspect, repair, and test all SSSVs in accordance with your Deepwater Operations Plan (DWOP) and	NOTE: "API RP 14B E.1.8 For oil wells, the pressure build-up depends on the static fluid level and the amount of gas in the oil. If the fluid level is below	OOC recommends revising the language to read: "You must install, maintain, inspect, and repair all SSSVs in accordance with your Deepwater Operations Plan (DWOP) and

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	API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems (ISO 10417:2004) (incorporated by reference as specified in § 250.198).	the SCSSV, the formulae for gas wells (E.1.7) can be used. If the fluid level is above the SCSSV, the leakage rate should be measured." You cannot use the formula provided for any well other than a dry gas well, and there is no method to measure the leakage in a subsea well. It must be calculated. The calculation may vary with tree configuration and may vary with tree (USV) valve leakage or failure.	API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems (ISO 10417:2004) (incorporated by reference as specified in § 250.198). SSSVs testing shall be in accordance with your Deepwater Operations Plan (DWOP), API RP 14B if applicable, or as approved by the District Manager."
250.829 (a)(3)	<u>Subsurface safety devices in shut-in wells – subsea trees.</u> A surface-controlled SSSV, provided the surface control has been rendered inoperative. For purposes of this section, a surface-controlled SSSV is considered inoperative if for a direct hydraulic control system you have bled the hydraulics from the control line and have isolated it from the hydraulic control pressure or if your controls employ an electro-hydraulic control umbilical and the hydraulic control pressure to the individual well cannot be isolated, and you perform the following: (i) Disable the control function of the surface-controlled SSSV within the logic of the programmable logic controller which controls the subsea well; (ii) Place a pressure alarm high on the control line to the surface-controlled SSSV of the subsea well; and (iii) Close the USV and at least one other tree valve on the subsea well.	The requirement to disable the control function of the SCSSV within the logic of the programmable logic controller which controls the subsea well would require a brownfield modification to the control logic. Such a change introduces more risk than it mitigates. The relevant SCSSV and USV valve functions can typically be locked out within the control system to prevent inadvertent access, without the need to modify the control logic itself. In combination with the measures required in sub-sub-paragraphs (ii) and (iii) locking out the SCSSV and USV control functions within the control system should be adequate. Suggest removing §250.829 (a)(3)(ii) since this pressure sensor is normally internal to the Subsea Control Module (SCM) and used for housekeeping only, it may not be available to the topside system. Also such sensors to do not have any rating of availability and are not intended for this kind of service, but are used for directional control valve status indication only.	OOC recommends revising the language to read: "You must install, maintain, inspect, repair, and test all SSSVs in accordance with your Deepwater Operations Plan (DWOP) or API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems (ISO 10417:2004) (incorporated by reference as specified in § 250.198)."
250.831	<u>Alteration or disconnection of subsea pipeline or umbilical.</u> If a necessary alteration or disconnection of the pipeline or umbilical of any subsea well affects your ability to monitor casing pressure or to test any subsea valves or equipment, you must contact the appropriate BSEE District Office at least 48 hours in advance and submit a repair or replacement plan to	This regulation is not needed. The process to repair or modify a subsea pipeline must be approved by the BSEE GOM Regional Pipeline Section. 30CFR250.520 requires continuous monitoring of subsea well production casing any deviation must approved by the district. SCSSVs and USVs are required to be tested at the frequency required in current	OOC recommends deleting this proposed regulation at 250.831.

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	conduct the required monitoring and testing. You must not alter or disconnect until the repair or replacement plan is approved.	30CFR250.804 and proposed 250.880	
250.833	Specification for underwater safety valves (USVs). All USVs, including those designated as primary or secondary and any alternate isolation valve (AIV) that acts as a USV, if applicable, and their actuators must conform to the requirements specified in §§ 250.801 through 250.803. A production master or wing valve may qualify as a USV under API Spec. 6AV1 (incorporated by reference as specified in § 250.198).		
250.833(a)	(a) Primary USV (USV1). You must install and designate one USV on a subsea tree as the USV1. The USV1 must be located upstream of the choke valve.	There are cases where redundant USVs are installed, therefore OOC recommends revising the language.	OOC recommends revising the language to read: "Should you choose to install redundant USVs. You must designate one USV on a subsea tree as USV1. The USV1 must be located upstream of the choke valve."
250.834	Use of USVs. You must install, maintain, inspect, repair, and test all USVs, including those designated as primary or secondary, and any AIV which acts as a USV if applicable in accordance with this subpart, your DWOP as specified in §§ 250.286 through 250.295, and API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (incorporated by reference as specified in § 250.198).	Secondary valves are not required; therefore testing them to the same standard as the primary should not be required until they become the primary USV. It is recommended that the new regulation be made fully consistent with the intent of the existing NTL No. 2009-G36 6, wherein it is only required for the USV designated as USV1 to pass the leak test criteria. The requirement to "test all USVs, including those designated as primary and secondary" means that USV2 needs to meet the leak test requirements specified in 250.880 (c)(4)(ii) even when USV1 is still fully functional and meeting the leak test requirements. When read in combination with the requirement to remove, repair and reinstall, or replace a leaking USV (as stated in 250.880 (c)(4)(ii)) this new requirement appears to mean that a subsea tree with a fully functional and sealing USV1 would be required to be retrieved just in order to repair or replace a leaking USV2. It is not	OOC recommends revising the language to read: "You must install, maintain, inspect, repair, and test any valve designated as the primary USV in accordance with this subpart, your DWOP as specified in §§ 250.286 through 250.295, and API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore (incorporated by reference as specified in § 250.198).

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		necessary (consistent with section 250.833) to require a subsea tree to be retrieved to repair or replace a leaking valve, while there is still at least 1 fully functional USV in service. Also, as written, the revision proposed does not directly refer to the testing requirements specified for USVs as described in 250.880. It is recommended that a reference to 250.880 should be included in 250.834.	
250.835	You must install a BSDV on the pipeline boarding riser. All BSDVs and their actuators installed in the OCS must meet the requirements specified in §§ 250.801 through 250.803 and the following requirements. You must:	See OOC comments regarding 250.803.	See OOC comments regarding 250.803
250.835(c)	Specification for all boarding shut down valves (BSDVs) associated with subsea systems	Recommend using API 14C current draft wording for BSDV location, along with engineering discretion in determining the appropriate location, with consideration for floating production systems, moon pool, etc. Being this prescriptive in the rule making, you lose the flexibility in the DWOP process.	OOC recommends revising the language to read: "Locate the BSDV as close to the water line as practical while providing safe and adequate access for operation, maintenance and testing. The piping outboard of the BSDV shall be protected from all credible hazards. For a floating production system, the first point of access to the boarding pipeline riser is considered to be the edge of the first accessible working deck, excluding the boat landing and above the splash zone."
250.836	Use of BSDVs. If any BSDV does not operate properly or if any fluid flow is observed during the leakage test, then you must shut-in all sources to the BSDV and repair or replace it before resuming production.	The requirement to repair or replace a leaking BSDV before resuming production as stated in 250.836, is not consistent with the requirement to immediately repair or replace the valve, as stated in 250.880 (c)(4)(iii).	OOC recommends that the language be consistent with 250.880(c)(4)(iii).

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Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
250.837 (a)	Emergency Action In the event of an emergency, such as an impending named tropical storm or hurricane, you must shut-in all subsea wells unless otherwise approved by the District Manager. A shut-in is defined as a closed BSDV, USV, and surface-controlled SSSV.	The term "impending named tropical storm or hurricane" needs to be better defined. There are some cases where named storms do not necessarily require shutting in. If the term is meant only as an example of an emergency and not meant to be all-inclusive, then recommend the wording to be clarified. Also, the title indicates emergency action, however, the only examples given reference tropical storms and hurricanes.	OOC recommends revising the title of this section and the language to read as follows: 250.837 - Tropical Storm/Hurricane Action (a) In the event of an emergency, such as an impending named tropical storm or hurricane, which would approach an active lease, in such a way that initiates implementation of the Lessee's Hurricane Preparedness/Evacuation Plan: (1) Any well not yet equipped with a subsurface safety device, such as temporary removal for routine operations, described in 250.817(a), and that is capable of natural flow must have the subsurface safety device properly installed as soon as possible, with due consideration being given to personnel safety. (2) You must shut-in all oil wells and gas wells unless otherwise approved by the District Manager in accordance with 250.141 or 250.142 or an approved SCADA plan.
250.837(b)(1)	(b) When operating a mobile offshore drilling unit (MODU) or other type of workover vessel in an area with producing subsea wells, you must: (1) Suspend production from all such wells that could be affected by a dropped object, including upstream wells that flow through the same pipeline; or	Currently operators are required to submit as part of the DWOP and the APD/APM as required by NTL 2009-G36. OOC recommends codifying the NTL.	OOC recommends revising the language to read: "Submit a plan to the appropriate District Manager for approval, as part of an application for a permit to drill or an application for permit to modify to address the risk of a dropped object."
250.838	What are the maximum allowable valve closure times and hydraulic bleeding requirements for an electro-hydraulic control system?	It is recommended that the word "rig" and the term "MODU" be replaced by "MODU/offshore support vessel" throughout.	

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Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
250.838(b)	(b) If you have not lost communication with your rig or platform, you must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP:	This requirement is confusing. It is inherent that if you have not lost communication, you must comply with the requirements.	OOC recommends revising the language to read: "You must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table(s) or your approved DWOP as long as communication is maintained."
250.838(d)	(d) If you experience a loss of communications, you must comply with the maximum allowable valve closure times and hydraulic system bleeding requirements listed in the following table or your approved DWOP.	The table needs to be consistent with the table outlined in NTL 2009-G36." This explains what to do in case you cannot meet those valve closure times when you have a loss of communications. Table referenced in Section 250.838(d)"" on line 5 requires immediate closure of tree valves upon Subsea ESD (MODU); Some control systems will not meet the timing requirement, especially with regards to the LP system. This would be typical of all other subsea projects."	"BSEE to allow alternate compliance as stated in NTL 2009-G36 Section 8, 30 CFR 250.803(b)(4)(ii), Additional production system requirements - ESD, Paragraph F"
250.839 (b)(5)	<u>What are the maximum allowable valve closure times and hydraulic bleeding requirements for direct hydraulic control system?</u> Dropped object – subsea ESD (MODU)	It is recommended that the word "rig" and the term "MODU" be replaced by "MODU/offshore support vessel" throughout.	
250.841	<u>Platforms</u>	Paragraph (b) is confusing regarding the temporary approvals by the District Manager. As written, it appears that the District Manager cannot approve any temporary repair for a total of 30 days. Currently the District Managers can approve any repair for a period of up to 30 days at any one time. Weather and logistics will play a key role when the permanent repair is actually conducted; however, it may take more than 30 days to actually complete the work. This recommended change will be in alignment with current agency policies. Reference to API 570 should not be included. API 570 was developed for downstream application and not offshore oil and gas upstream application. As such, there are many	OOC recommends changing paragraph (b) to read: "(b) You must design, analyze, install, test, and maintain in operating condition all platform production process piping in accordance with API RP 14E, Design and Installation of Offshore Production Platform Piping Systems ~~and API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems~~ (both incorporated by reference as specified in § 250.198). The District Manager may approve temporary repairs to facility piping on a case-by-case basis for a period not to exceed 30 days at any one time." OOC recommends deleting reference to API 570 from "documents incorporated by reference" and this citation.

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		conflicts within the document related to offshore operations and before the document is incorporated in its entirety, the agency should review the document and determine what sections would be applicable to offshore production operations.	
250.842 (a) (1)	<u>Approval of safety systems design and installation features</u> (a) Before you install or modify a production safety system, you must submit a production safety system application to the District Manager for approval. The application must include the information prescribed in the following table: You must submit: (1) A schematic piping and instrumentation diagram Showing the following: (i) Well shut-in tubing pressure; (ii) Piping specification breaks, piping sizes; (iii) Pressure relief valve set points; (iv) Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, treaters, storage tanks, compressors and metering devices; (v) Size, capacity, design working pressures, and maximum discharge pressure of hydrocarbon handling pumps; (vi) size, capacity, and design working pressures of hydrocarbon-handling vessels, and chemical injection systems handling a material having a flash point below 100 degrees Fahrenheit for a Class I flammable liquid as described in API RP 500 and 505 (both incorporated by reference as specified in § 250.198).	The requirement to have and maintain two sets of drawings becomes burdensome and creates opportunities for errors and omissions to occur. Further the preamble references the Atlantis investigation in justifying the new requirements for drawings; however, the recommendations from the Atlantis report did not identify a need for revisions to the drawing(s) requirements of subpart H. The recommendations from the Atlantis report address issues currently covered in Subpart I.	OOC recommends revising this section to combine (a)(1) and (2) to read: "(1) A Process Safety Flow Diagram, ….. which would include all elements of the Safety Analysis Flow Diagram (API RP 14C, Appendix E), Showing the following: i – System-piping specification breaks, piping sizes; ii – Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, treaters, storage tanks, and compressors; iii - Size, capacity and design working pressures, and maximum discharge pressure of hydrocarbon-handling pumps iv – Size, capacity and design working pressures of hydrocarbon handling vessels, and permanently installed high volume chemical injection systems handling a material having a flash point below 100 degrees Fahrenheit for a Class I flammable liquid as described in API RP 500 and 505 (both incorporated by reference as specified in 250.198). v – Size and maximum allowable pressures as determined in accordance with API RP 14E, Recommended Practice for

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	(vii) Size and maximum allowable working pressures as determined in accordance with API RP 14E, recommended Practice for Design and Installation of Offshore Production Platform Piping Systems (incorporated by reference as specified in § 250.198).		Design and Installation of Offshore Production Platform Piping Systems (incorporated by reference as specified in 250.198). (2) Safety Analysis Function Evaluation (SAFE) chart (API RP 14C, subsection 4.3.3) (incorporated by reference as specified in 250.198). (d) Insert "process safety flow diagrams" as appropriate… (f) Insert "process safety flow diagrams" as appropriate…
250.842 (a) (3)	<u>§ 250.842 Approval of safety systems design and installation features.</u> (a) Before you install or modify a production safety system, you must submit a production safety system application to the District Manager for approval. The application must include the information prescribed in the following table: You must submit: (3) Electrical system information, including … (i) A plan for each platform deck and outlining all classified areas. You must classify areas according to API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2; or API RP 505, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2 (both incorporated by reference as specified in § 250.198). (ii) Identification of all areas where potential ignition sources, including non-electrical ignition sources, are to be installed showing: (A) All major production equipment, wells, and other		

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	significant hydrocarbon sources, and a description of the type of decking, ceiling, and walls (e.g., grating or solid) and firewalls and; (B) the location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the primary wiring method (e.g., type cable, conduit, wire) and; (iii) one-line electrical drawings of all electrical systems including the safety shutdown system. You must also include a functional legend.		
250.842(a)(3) (iii)	(iii) one-line electrical drawings of all electrical systems including the safety shutdown system. You must also include a functional legend.	Since scope is expanded to include additional one line electrical drawings for all electrical systems, OOC recommends that BSEE limit this requirement to submittals for new facilities only.	OOC recommends that BSEE limit this requirement to submittals for new facilities only.
250.842 (a) (4)	<u>§ 250.842 Approval of safety systems design and installation features.</u> (a) Before you install or modify a production safety system, you must submit a production safety system application to the District Manager for approval. The application must include the information prescribed in the following table: You must submit: (4) Schematics of the fire and gas-detection systems showing a functional block diagram of the detection system, including the electrical power supply and also including the type, location, and number of detection sensors; the type and kind of alarms, including emergency equipment to be activated; the method used for detection; and the method and frequency of calibration		OOC recommends that BSEE limit this requirement to submittals for new facilities only.
250.842 (b)	<u>Approval of safety systems design and installation features.</u> The production safety system application must also include the following certifications: (1) That all electrical installations were designed according to	The bureau is attempting to use the Atlantis report to modify this portion of the regulations. The preamble references the Atlantis investigation in justifying the new requirements (stamping) for drawings; however, the recommendations from the Atlantis report did not identify a need for revisions to the	OOC recommends that paragraph (b)(2) be revised to read: " (b) The production safety system application must also include the following certifications signed by your authorized representative:

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	API RP 14F, Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1 and Division 2 Locations, or API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, as applicable (incorporated by reference as specified in § 250.198); (2) That the designs for the mechanical and electrical systems were reviewed, approved, and stamped by a registered professional engineer(s). The registered professional engineer must be registered in a State or Territory in the United States and have sufficient expertise and experience to perform the duties; and	drawing(s) requirements of subpart H. The recommendations from the Atlantis report address issues currently covered in Subpart I. Further the proposed regulations limit the certifications (by omission) to US professional engineers. Suggest revising the language in §250.842(b)(2) to allow chartered engineers and other non-US engineers to design mechanical and electrical systems, to review, and to approve these documents, as a large number of floating structures are engineered and built outside the US. The current proposed wording may also introduce significant legal issues when applied to modifications on existing facilities. Certification must be limited to that which is "to be installed." "Stamping" of every individual page is not recognized PE protocol.	(1You must certify that all electrical installations were designed according to API RP 14F, Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Division 1 and Division 2 Locations, or API RP 14FZ, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class I, Zone 0, Zone 1 and Zone 2 Locations, as applicable (incorporated by reference as specified in § 250.198); (2) You must certify that the designs for the mechanical and electrical systems were reviewed and approved by a registered professional engineer(s) or equivalent with sufficient expertise and experience to perform the duties. The registered professional engineer must be registered in a State or Territory in the United States or chartered or recognized as a professional engineer in a country outside of the United States.
250.842(b)(3)	(3) That a hazard analysis was performed during the design process in accordance with API RP 14J (incorporated by reference as specified in § 250.198), and that you have a hazards analysis program in place to assess potential hazards during the operation of the platform.	The requirement to conduct a hazards analysis (HA) is dictated by Subpart S and API RP 75. The criteria for conducting a HA is dictated by Subpart S and RP75. Typically, a HA is done during the original designing process and then periodically (5-10 year cycle) based on the complexity of the facility. Modifications (to either the facility or safety system) are governed by the Management of Change process and may or may not dictate that a HA needs to be conducted following a modification. The reference "during the design process is confusing in that it is	OOC first recommends that paragraph (3) be deleted in its entirety. Should the bureau choose to reject this first recommendation, the OOC suggests, as a minimum, that the bureau revise paragraph (3) to read: "(3)You must certify that a hazard analysis was performed in accordance with Subpart S and API RP 14J (incorporated by reference as specified in 250.198), and that you have a hazards

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		vague as to which "design" the bureau is referencing. Are we talking about the original design process or the design process of the modification?? OOC recommends revising the language to remove the "design process." The placement of this requirement here is confusing given that HA are covered and governed by Subpart S, RP 75, and RP 14J. Any change with respect to HA's, should be done as part of Subpart S and/or RP 75 and 14J.	analysis program in place to assess potential hazards during the operation of the platform."
250.842 (c)	(c) Before you begin production, you must certify, in a letter to the District Manager, that the mechanical and electrical systems were installed in accordance with the approved designs.	For clarification recognizing other means of communication.	(c) Before you begin production, you must provide the following certification to the District Manager: You must certify that the mechanical and electrical systems were installed in accordance with the approved designs.
250.842 (d)	(d) Within 60 days after production, you must certify, in a letter to the District Manager, that the as-built diagrams outlined in (a)(1) and (2) of this section and the piping and instrumentation diagrams are on file and have been certified correct and stamped by a registered professional engineer(s). The registered professional engineer must be registered in a State or Territory in the United States and have sufficient expertise and experience to perform the duties.	In following with OOC comments regarding (a)(1) above, OOC recommends that all references to "piping and instrument diagrams" be replaced with "process safety flow diagram" The 60 days allotted are not sufficient to validate the drawings as correct, certify the drawings as correct, and submit to the bureau.	In following with OOC comments regarding (a)(1)) above, OOC recommends that all references to "piping and instrument diagrams" be replaced with "process safety flow diagram" (d) Within 180 days after production, you must provide a copy of the as-built diagrams outlined in (a)(1) of this section along with the following certification to the District Manager: You must certify that the as-built diagrams outlined in (a)(1) of this section have been reviewed and verified to be in accordance with the approved design by a registered professional engineer or equivalent with sufficient expertise and experience to perform the duties. The drawings must be kept on file at a secure onshore location and readily available offshore for the facility to which they are applicable. The registered professional engineer must be registered in a State or Territory in the United States or chartered or recognized as a professional engineer in a country outside of the United States.

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250.842 (e)	(e) All as-built diagrams outlined in (a)(1) and (2) of this section must be submitted to the District Manager within 60 days after production.	This is a new requirement for which the intent is not understood. BSEE will have the original design drawings as part of the application. BSEE will have the certification that the installation was done in accordance with the approved drawings. This requirement creates an undue paperwork burden on both the company and the bureau and OOC believes the costs for maintaining the "as-built" drawings has been severely underestimated.	OOC recommends that this requirement be deleted.
250.842 (f)	(f) You must maintain information concerning the approved design and installation features of the production safety system at your offshore field office nearest the OCS facility or at other locations conveniently available to the District Manager. As-built piping and instrumentation diagrams must be maintained at a secure onshore location and readily available offshore. These documents must be made available to BSEE upon request and be retained for the life of the facility. All approvals are subject to field verifications.	In following with OOC comments regarding (a)(1) and (2) above, OOC recommends that all references to "piping and instrument diagrams" be replaced with "process safety flow diagram" In following OOC's comment for paragraph (e) above, OOC recommends the changes noted. OOC does not understand the need for the statement, "All approvals are subject to field verification." This is a standard practice with any inspection and enforcement process and is not necessary.	In following with OOC comments regarding (a)(1) and (2) above, OOC recommends that all references to "piping and instrument diagrams" be replaced with "process safety flow diagram" OOC recommends that paragraph (f) be revised to read: "You must maintain information concerning the approved design and installation features of the production safety system at your offshore field office nearest the OCS facility or at other locations conveniently available to the District Manager. The documents, along with the as-built diagrams outlined in (a)(1) must be made available to BSEE upon request and retained for the life of the facility."
250.851(a)(1)	(1) Pressure and fired vessels where the operating pressure is or will be 15 pounds per square inch gauge (psig) or greater.	This is inconsistent with ASME BPVC.	OOC recommends revising to be in alignment with established codes to read: "(1) Pressure and fired vessels where the operating pressure is greater than 15 pounds per square inch gauge (psig)."
250.851(a)(2)	(2) Pressure and fired vessels (such as flare and vent scrubbers) where the operating pressure is or will be at least 5 psig and less than 15 psig.	This is inconsistent with ASME BPVC.	OOC recommends revising to be in alignment with established codes to read: "(1 Pressure and fired vessels (such as flare and vent scrubbers) where the operating pressure is or will be at least 5 psig and equal to or less than 15 psig
250.851(a)(4)	(4) Existing uncoded Pressure and fired vessels (i) in use on the effective date of the final rule; (ii) with an operating pressure	This is inconsistent with ASME BPVC.	OOC recommends revising to be in alignment with established codes to read:

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	of 5 psig or greater; and (iii) that are not code stamped in accordance with the ANSI/ASME Boiler and Pressure Vessel Code…		"(4) Existing uncoded Pressure and fired vessels (i) in use on the effective date of the final rule; (ii) with an operating pressure greater than 15 psig or greater; and (iii) that are not code stamped in accordance with the ASME Boiler and Pressure Vessel Code…."
250.851 (a)(5)	Pressure relief valves. (ii) Must conform to the valve sizing and pressure-relieving requirements specified in these documents, but (except for completely redundant relief valves), must be set no higher than the maximum-allowable working pressure of the vessel. (iii) …	While this proposal attempts to account for the need to stagger relief valve set pressures, it may have missed the point depending on the term "completely redundant relief valve" and could allow a potentially unsafe condition. Some equipment can have multiple causes (contingencies) for high pressure, each of which may produce different amounts of vapor (loads) that need to be "relieved" through the relief valve or valves. It is not uncommon for a piece of equipment to have some contingences that require multiple relief valves another contingency could be relieved through a single valve. These relief valves may not be the same size and must be available for the larger contingency. One common example is a vessel where the blocked vapor outlet case requires much less relief capacity than vapor blow-by from an upstream vessel. Making all the set pressures the same can lead to relief valve chatter, which is the rapid opening and closing of the relief valve. The consequences of chatter can range from common cases of valve seat damage, which results in leakage into the environment through the valve discharge, to documented cases of valve and or associated piping failure which leads to a potentially hazardous loss of primary containment of the fluids in the protected equipment. In the case of a truly "completely redundant" or spare relief valve, the set pressure should be the same as the valve it is replacing (redundant to). In this case the completely redundant (installed spare) relief valve should be fitted with an inlet block valve and this block valve should be closed. If the	OOC recommends revising language to read: "(ii) Must conform to the valve sizing and pressure-relieving requirements specified in these documents, but must be set no higher than the maximum-allowable working pressure of the vessel (except for cases where staggered set pressures are required for configurations using multiple relief valves or redundant valves installed and designated for operator use only),

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
		primary relief valve needs to be isolated or removed, in case of malfunction, maintenance, etc., the redundant (spare) relief inlet valve block valve is opened and the primary relief inlet valve block valve is closed providing continuous protection. More details on relief valve sizing and prevention of chatter by staggering set pressures can be found in API standard 521. Limits on staggering set pressures can be found in API standard 521 and is ASME Section VIII division 1.	
250.851 (b)	Pressure vessels (including heat exchangers) and fired vessels (b) Operating pressure ranges. You must use pressure recording devices to establish the new operating pressure ranges of pressure vessels at any time the normalized system pressure changes by 5 percent. You must maintain the pressure recording information you used to determine current operating pressure ranges at your field office nearest the OCS facility or at another location conveniently available to the District Manager for as long as the information is valid.	Most operators do not monitor the operating ranges to see if they fluctuate 5%, as such fluctuations do not typically indicate a change in the maximum operating pressure. OOC believes the current practice of ensuring we are below the maximum operating pressure is more than sufficient to ensure proper operation. To implement this new requirement, industry would need to institute new field protocols to observe this. It is not clear that this new requirement would add value beyond current requirements, though it clearly would require additional resources by the operator.	OOC recommends revising this paragraph to read: "(b) You must use pressure recording devices to establish the new operating pressure ranges of pressure vessels at any time when the normal system pressure changes by 15 percent or 5 psi, whichever is greater."
250.852	<u>**Flowlines/Headers**</u>		
250.852 (a)(2)	(2) You must use pressure recording devices to establish the new operating pressure ranges of flowlines at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher.	Most operators do not monitor the operating ranges to see if they fluctuate 5%, as such fluctuations do not typically indicate a change in the maximum operating pressure. OOC believes the current practice of ensuring we are below the maximum operating pressure is more than sufficient to ensure proper operation. To implement this new requirement, industry would need to institute new field protocols to observe this. It is not clear that this new requirement would add value beyond current requirements, though it clearly would require additional resources by the operator.	OOC recommends revising the language to read: "(2) You must use pressure recording devices to establish the new operating pressure ranges of flowlines at any time when the normal system pressure changes by 15 percent or 5 psi, whichever is higher.
250.852 (c)(2)		The proposed language conflicts with the current language in Subpart J (Pipelines) and also with the recommended guidance in RP 14C. OOC recommends deleting the requirement for the	

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
		PSV when the SITP is greater than 1.5 times the MAWP of the pipeline/flowline. Currently with the two SSVs with independent PSHs, a SIL level of 2 is achieved when both SSVs are required to hold bubble tight (zero leakage). The 2nd SSV serves as an alternate safety device to prevent over pressure of the pipeline.	
250.853 (d)	Safety sensors. All level sensors are equipped to permit testing through an external bridle on all new vessel installations.	The requirement that level sensors be located on an external bridle (rather than directly on the vessel) is unnecessary, as long as a means of testing the sensor without a level bridle is available. Fouling or foaming services may cause external bridle sensors to misread level in some services. Certain technologies (e.g., ultrasonic and capacitance) are not suitable for use in external bridles. Some proposed/new projects are evaluating using ultrasonic, optical, microwave, conductive, or capacitance sensors. These sensors do not utilize bridals. This is new technology and BSEE needs to understand this technology cannot be placed on a bridle. BSEE needs to remove (d) from the new regulations. BSEE needs to reword this to allow for new technology that does not utilize bridles for sensing.	OOC recommends revising the language to read: "§250.853 (d) All level sensors are equipped to permit testing through an external bridle on all new vessel installations where practical depending on the type of vessel for which the level sensor is used."
250.854 (b)	Floating production units equipped with turret and turret mounted systems. For floating production units equipped with swivel stack arrangements, you must equip the portion of the swivel stack containing hydrocarbons with a leak detection system. Your leak detection system must be tied into your production process surface safety system allowing for automatic shut-in of the system. Upon seal system failure and detection of a hydrocarbon leak, your surface safety system must immediately initiate a process system shut-in according to §§ 250.838 and 250.839.	Suggest revising the language of §250.854(b) since on many swivel stacks with leak detection systems, the "detection of a hydrocarbon leak" is not the criteria for an auto shut down - the rate of the leak is. This is because the seals can and do operate with sometimes slow minor leaks that are contained by a leak recuperation system.	OOC recommends revising the paragraph to read: "(b) For floating production units equipped with swivel stack arrangements, you must equip the portion of the swivel stack containing hydrocarbons with a leak detection system. Your leak detection system must be tied into your production process surface safety system allowing for automatic shut-in of the system. Upon seal system failure and detection of a hydrocarbon leak (or, where a leak recuperation system is used, a hydrocarbon leak exceeding permitted leak rates managed by the leak recuperation system), your surface safety system must immediately initiate a process system shut-in

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Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
			according to §250.838 and §250.839."
250.858(b)	(b) You must use pressure recording devices to establish the new operating pressure ranges for compressor discharge sensors at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. You must:	Most operators do not monitor the operating ranges to see if they fluctuate 5%; as such fluctuations do not typically indicate a change in the maximum operating pressure. OOC believes the current practice of ensuring we are below the maximum operating pressure is more than sufficient to ensure proper operation. To implement this new requirement, industry would need to institute new field protocols to observe this. It is not clear that this new requirement would add value beyond current requirements, though it clearly would require additional resources by the operator.	OOC recommends revising this paragraph to read: "(b) You must use pressure recording devices to establish the new operating pressure ranges for compressor discharge pressure at any time when the normal system pressure changes by 15 percent or 5 psi, whichever is greater"
250.859(a) 250.859(a)(1) 250.859(a)(2)	Firefighting systems Firefighting systems for both open and totally enclosed platforms installed for extreme weather conditions or other reasons must conform to API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms (incorporated by reference as specified in § 250.198), and require approval of the District Manager. The following additional requirements apply for both open- and closed-production platforms: You must install a firewater system consisting of rigid pipe with fire hose stations fixed firewater monitors. The firewater system must protect in all areas where production-handling equipment is located. You must install a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate. Fuel or power for firewater pump drivers must be available for at least 30 minutes of run time during a platform shut-in. If necessary, you must install an alternate fuel or power supply to provide for this pump operating time unless the District	OOC offers several recommendations based on BSEE's intent regarding firefighting. Background: Prior to the Notice of Proposed Rule (NPR), BSEE required that Lessees comply with only Section 5.2 of API RP 14G (14G) with regards to firewater systems. Since BSEE's current regulations require a firewater system to be installed on fixed platforms, Section 5 addresses the design, piping and associated components, which to consider when designing, maintaining a firewater system, unless a departure was requested and granted by BSEE, to use chemical in lieu of a firewater system. The other sections within 14G, such as fire detectors and gas sensors, are covered under other referenced API documents. The proposed rule requires the inclusion of API RP 14G (RP) in its entirety. While we agree that the inclusion of certain sections will enhance safety, we disagree that the incremental benefits of incorporating the entire 14G standard will justify the increased costs. 14G does not offer a "cookbook" method of designing and installing a complete firefighting system; instead, 14G offers recommended criteria for whatever firefighting system the operator chooses to install. For example, if the operator wants to install a firewater system only, then the operator would only need to comply	OOC recommends the following revisions that will help clarify the requirements for fixed facilities as well as floating facilities and will account for currently approved systems in service today. Specifically, OOC recommends revising paragraph (a) and adding a new paragraph (b) and renumbering paragraph (c) to read: "(a) On fixed facilities, you must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed firewater monitors. The firewater system must protect in all areas where production-handling equipment is located. You must install a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate. (1) Your firewater system must conform to those applicable sections of API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms (incorporated by reference as specified in § 250.198). (2) Fuel or power for firewater pump drivers must be available for at least 30 minutes of run time during a platform shut-in. If necessary, you must install an alternate fuel or power supply to provide for this

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	Manager has approved an alternate firefighting system. As of 1 year after the publication date of the final rule, you must have equipped all new firewater pump drivers with automatic starting capabilities upon activation of the ESD, fusible loop, or other fire detection system. For electric driven firewater pump drivers, in the event of a loss of primary power, you must install an automatic transfer switch to cross over to an emergency power source in order to maintain at least 30 minutes of run time. The emergency power source must be reliable and have adequate capacity to carry the locked-rotor currents of the fire pump motor and accessory equipment. You must route power cables or conduits with wires installed between the fire water pump drivers and the automatic transfer switch away from hazardous-classified locations that can cause flame impingement. Power cables or conduits with wires that connect to the fire water pump drivers must be capable of maintaining circuit integrity for not less than 30 minutes of flame impingement.	with only those sections that would apply to firewater systems (5.2-Fire Water Systems, 7.2 – Fire Water Pump Inspection, Testing, & Maintenance, 7.3 – Fire Hoses, Nozzles, and Monitors, 7.4 Deluge and Sprinkler Systems, and Appendix D – Fire Water Piping Selection). BSEE does not take into account existing systems that have been approved under the current regulations and current approval/inspection policies. To compound the problem even more, BSEE does not take into account the conflicts created with the USCG fire-fighting requirements for floating facilities. While we agree the requirements may be similar, BSEE must agree that they are also different. Review: A thorough and comprehensive review of 14G reveals that this is document will create undue burdensome requirements on an operator to comply with the new rule for existing facilities should BSEE include the entire 14G. As discussed below, some of the requirements address issues over which the operator has no control. A partial listing of those major changes are listed below: • Section 3.2, paragraph i.3, requires helicopters to be equipped with self-releasing or spring-clamp bond cable. • Section 5.4, paragraph e.1, requires foam systems to be installed on hydrocarbon or flammable substance tanks of volumes in excess of 100 barrels. If chemical fire systems are currently approved, foam systems are required to be installed. Does this mean that platforms with firewater systems will be required to install foam systems on existing tanks? • Section 5.4, paragraph e.2, requires storerooms for paint or other flammable or combustible liquids and has an area of 200 sq. ft. be equipped with a fixed sprinkler, watermist or gaseous extinguishing system. • Section 5.4, paragraph e.3, requires spaces or enclosures containing internal combustion engines in excess of 1,000bhp	pump operating time unless the District Manager has approved an alternate firefighting system. As of 1 year after the publication date of the final rule, you must have equipped all new firewater pump drivers with automatic starting capabilities upon activation of the ESD, fusible loop, or other fire detection system. For electric driven firewater pump drivers, in the event of a loss of primary power, you must install an automatic transfer switch to cross over to an emergency power source in order to maintain at least 30 minutes of run time. The emergency power source must be reliable and have adequate capacity to carry the locked-rotor currents of the fire pump motor and accessory equipment. You must route power cables or conduits with wires installed between the fire water pump drivers and the automatic transfer switch away from hazardous-classified locations that can cause flame impingement. Power cables or conduits with wires that connect to the fire water pump drivers must be capable of maintaining circuit integrity for not less than 30 minutes of flame impingement. (3) You must post a diagram of the firefighting system showing the location of all firefighting equipment in a prominent place on the facility or structure. (4) For operations in subfreezing climates, you must furnish evidence to the District Manager that the firefighting system is suitable for those conditions. (5) You must obtain approval from the District Manager before installing any firefighting system. (6) All firefighting equipment located on a facility must be in good working order whether approved as the primary, secondary, or ancillary firefighting system. (b) On floating facilities, you must install a firewater system consisting of rigid pipe with fire hose stations and/or fixed
250.859(a)(3)	You must post a diagram of the firefighting system showing the location of all firefighting equipment in a prominent place on the facility or structure.		
250.859(a)(4)	For operations in subfreezing climates, you must furnish evidence to the District Manager that the firefighting system is suitable for those conditions.		
250.859(a)(5)	All firefighting equipment located on a facility must be in good working order whether approved as the primary, secondary, or ancillary firefighting system.		

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
250.859(b)	Inoperable Firewater Systems. If you are required to maintain a firewater system and it becomes inoperable, either shut-in your production operations while making the necessary repairs, or request that the appropriate BSEE District Manager grant you a departure under § 250.142 to use a firefighting system using chemicals on a temporary basis (for a period up to 7 days) while you make the necessary repairs. If you are unable to complete repairs during the approved time period because of circumstances beyond your control, the BSEE District Manager may grant extensions to your approved departure for periods up to 7 days.	should be protected by a fixed sprinkler, watermist or gaseous extinguishing system • Section 5.4, paragraph e. 4, requires facilities with quarters and cooking facilities, cooking surfaces should be protected by a range hood and dry chemical extinguishers, as long as the quantities of portable extinguishers are no less than that recommended under 6.2. • Section 5.8, Emergency Depressurizing, this section would require facilities to be retro fitted with an automatic depressurizing system. Depressurizing in some circumstances may actually increase risk unless major modifications are made to safely discharge the release. Such a situation would be a facility which includes substances such as H2S, where depressurizing would usually increase danger to personnel. • Section 9, Passive Fire Protection, this section requires facilities to be equipped with passive fire protection, such as fire resistant coatings on structural members. Passive fire protection only "buys time" for implementation of other protective systems or response plans such as emergency shutdown of the facility. Apache and other operators only fight incipient fires. Personnel are trained to safely evacuate in the event of an emergency. The incremental benefits of installing passive fire protection on existing facilities would not justify the cost since BSEE requires a specific time limit on shut in of sources (wells and pipelines). OOC is concerned that some passive fire protection (such as structural coatings) will affect our ability to monitor for corrosion. However, passive fire protection such as use of fire blankets when required is already in use. Use of temporary shielding during certain operations is already required for welding and safe burning per current regulations. In review of 14G, numerous sections are already addressed in other referenced API RP documents, such as API RP 14C, 14 F	firewater monitors. The firewater system must protect in all areas where production-handling equipment is located. You must install a fixed water spray system in enclosed well-bay areas where hydrocarbon vapors may accumulate. Your firewater system must conform to the USCG requirements for firefighting systems on floating facilities. (c) Inoperable Firewater Systems. If you are required to maintain a firewater system and it becomes inoperable, either shut-in your production operations while making the necessary repairs, or request that the appropriate BSEE District Manager grant you a departure under § 250.142 to use a firefighting system using chemicals on a temporary basis (for a period up to 7 days) while you make the necessary repairs. If you are unable to complete repairs during the approved time period because of circumstances beyond your control, the BSEE District Manager may grant multiple extensions to your approved departure for periods up to 7 days each. _________________________ Should BSEE reject the above recommendation that accounts for existing systems meeting the proposed requirements, then OOC recommends revising paragraph (a), inserting new paragraph (b) and re-lettering existing paragraph (b) to paragraph (c) to read: (a) Any firefighting system installed after [insert date 2 years following effective date of final rule] for both open and totally enclosed <u>fixed</u> platforms installed for extreme weather conditions or other reasons must conform to API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms (incorporated by reference as specified in § 250.198), <u>as applicable</u>, and require approval of the District Manager.

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
		& FZ, 14E 14J 75, of which an operator must comply with. This additional protection increases high cost of compliance particularly on existing platforms. Conclusion: The additional requirements with the implementation of the entire 14G will not reduce the likely hood of a fire, nor will the implementation increase the chances to effectively fight a fire, since most operators prohibit employees from fighting fires outside of those of the incipient stage. Additionally, if older facilities are not grand fathered to those sections of API 14G not previously incorporated, facilities with marginal production will have to be shut-in and abandoned with reserves being unexploited. Numerous older and smaller facilities will not be able to comply with the incorporation of the entire 14G due to their tight configuration and placement of equipment already in place. Lastly, without knowing BSEE's intent with this revision, it appears that BSEE may not have fully evaluated the economic impact of this revised rule on existing operations. OOC recommends several options for accommodating existing systems by adding language similar to the current language that addresses crane requirements for fixed facilities. Additionally, OOC recommends separating the firefighting requirements for floating facilities since this is driven mainly by the USCG.	The following additional requirements apply for both open- and closed-production platforms:……….." (b) Any firefighting system installed after [insert date 2 years following effective date of final rule] on floating production facilities, must conform to the USCG requirements for firefighting systems." (c) (c) Inoperable Firewater Systems. If you are required to maintain a firewater system and it becomes inoperable, either shut-in your production operations while making the necessary repairs, or request that the appropriate BSEE District Manager grant you a departure under § 250.142 to use a firefighting system using chemicals on a temporary basis while you make the necessary repairs. If you are unable to complete repairs during the approved time period because of circumstances beyond your control, the BSEE District Manager may grant multiple extensions to your approved departure for periods up to 7 days each.
250.860	Chemical firefighting systems	BSEE has attempted to codify the existing NTL regarding Fire Prevention and Control System (2006-G04); however, BSEE has not indicated how the required risk assessment criteria will be evaluated. OOC understands that a risk matrix has been developed by BSEE for use in evaluating an operator's risk assessment. OOC requests that the risk assessment criteria be included with this portion of the rule so that operators can do preliminary assessments to determine if approval will be possible. Including the risk matrix will save both the operator	OOC recommends including the BSEE risk matrix with the risk assessment criteria.

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
		and BSEE time for review and potential approval if some requests can be evaluated before event being submitted to BSEE.	
250.861	<u>Foam firefighting system</u> (a) Annually conduct an inspection of the foam concentrates and their tanks or storage containers for evidence of excessive sludging or deterioration. (b) Annually send samples of the foam concentrate to the manufacturer or authorized representative for quality condition testing. You must have the sample tested to determine the specific gravity, pH, percentage of water dilution, and solid content. Based on these results, the foam must be certified by an authorized representative of the manufacturer as suitable firefighting foam per the original manufacturer's specifications. The certification document must be readily accessible for field inspection. In lieu of sampling and certification, you may choose to replace the total inventory of foam with new stock.	This section should be deleted. See OOC Attachment 4 – OOC Comments – BSEE/USCG Jurisdictional Areas of Responsibility For both fixed and floating facilities, USCG has been given jurisdiction over most of the fire protection, detection and extinguishing systems. The only area that is not covered is firefighting in the production handling area. The regulations should be limited to this area only. All discussion concerning firefighting in other areas, including well bay, should be removed along with requirements for fire water pumps. All discussion of firewater systems, chemical firefighting systems and foam systems should be clarified to state that they apply only to the production handling area. USCG has jurisdiction for fire and smoke detection, so those requirements should be limited to interfaces with BSEE systems, such as the ESD system.	OOC recommends that the bureau clarify that this requirement applies only to foam systems that are integrated into fire-water systems that protect production handling areas.
250.862(a)	You must install fire (flame, heat, or smoke) sensors in all enclosed classified areas. You must install gas sensors in all inadequately ventilated, enclosed classified areas. Adequate ventilation is defined as ventilation that is sufficient to prevent accumulation of significant quantities of vapor-air mixture in concentrations over 25 percent of the lower explosive limit. An acceptable method of providing adequate ventilation is one that provides a change of air volume each 5 minutes or 1 cubic foot of air-volume flow per minute per square foot of solid floor area, whichever is greater.	Refer to Attachment 4 – OOC Comments – BSEE/USCG Jurisdictional Areas of Responsibility	
250.862(e)	Fire and gas-detection systems	Refer to Attachment 4 – OOC Comments – BSEE/USCG Jurisdictional Areas of Responsibility	

Attachment 1 – OOC Detailed Comments on Subpart H Proposed Rule

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
250.864	Erosion. You must have a program of erosion control in effect for wells or fields that have a history of sand production. The erosion-control program may include sand probes, X-ray, ultrasonic, or other satisfactory monitoring methods. You must maintain records by lease that indicate the wells that have erosion-control programs in effect. You must also maintain the results of the programs for at least 2 years and make them available to BSEE upon request.	This section could be made clearer if it addressed corrosion monitoring and corrosion control as two separate aspects of a total corrosion management program. We recommend changes to make it a requirement to implement an erosion monitoring program for wells or fields that have a history of (or could reasonably be expected to encounter) erosion due to sand production - this could then be tied to a requirement to implement an erosion control program if required. Not all fields/wells/leases would require an erosion control program.	
250.865(a)	Surface pumps You must equip pump installations with the protective equipment required in API RP 14C, Appendix A — A.7, Pumps section A7 (incorporated by reference as specified in § 250.198).	It is unclear as to what "pumps" this requirement applies. OOC assumes that this only applies to those pumps in the production process, pipeline transfer, small volume produced hydrocarbon transfer, or other process fluids transfer pumps as recognized in 14C.	OOC recommends BSEE clarify this requirement to indicate only those pumps specifically recognized in API RP 14C.
250.865(b)	Surface pumps You must use pressure recording devices to establish the new operating pressure ranges for pump discharge sensors at any time when the normalized system pressure changes by 50 psig or 5 percent, whichever is higher. You must only maintain the most recent pressure recording information that you used to determine operating pressure ranges at your field office	Most operators do not monitor the operating ranges to see if they fluctuate 5%, as such fluctuations do not typically indicate a change in the maximum operating pressure. OOC believes the current practice of ensuring we are below the maximum operating pressure is more than sufficient to ensure proper operation. To implement this new requirement, industry would need to institute new field protocols to observe this. It	OOC recommends revising this paragraph to read: "(b) You must use pressure recording devices to establish the new operating pressure ranges of pump discharges at any time when the normal system pressure changes by 15 percent or 5 psi, whichever is greater."

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	nearest the OCS facility or at another location conveniently available to the District Manager. The PSH sensor(s) must be set no higher than 15 percent or 5 psi, whichever is greater, above the highest operating pressure of the discharge line. But in all cases, you must set the PSH sensor sufficiently below the maximum allowable working pressure of the discharge piping. In addition, you must set the PSH sensor(s) at least (5 percent or 5 psi, whichever is greater) below the set pressure of the PSV to assure that the pressure source is shut-in before the PSV activates. You must set the PSL sensor(s) no lower than 15 percent or 5 psi, whichever is greater, below the lowest operating pressure of the discharge line in which it is installed.	is not clear that this new requirement would add value beyond current requirements, though it clearly would require additional resources by the operator.	
250.865(f)	The pump maximum discharge pressure must be determined using the maximum possible suction pressure and the maximum power output of the driver.	Depending on the pump type(s), the maximum discharge pressure is not always determined by suction pressure and maximum output of the driver.	OOC recommends revising the language to read: "The pump maximum discharge pressure must be determined considering the maximum suction pressure and the power output of the driver as appropriate for pump type and service."
250.866	<u>§ 250.866 Personnel safety equipment.</u> You must maintain all personnel safety equipment located on a facility, whether required or not, in good working condition.	This requirement is out of place in this section. This is a general duty statement that belongs in Subpart A at 250.107. Further, specific regulations regarding personnel safety equipment are covered by the USCG in Subchapter N of Title 33.	OOC recommends deleting this statement from Subpart H altogether.
250.867	Temporary Quarters (b) The District Manager may require you to install a temporary firewater system in temporary quarters.	OOC believes that BSEE has overstepped its boundary of authority. Fire-fighting requirements for accommodation and machinery spaces are the responsibility of the USCG. Additionally, there are no BSEE requirements in either the existing regulations or the proposed regulations that require fire water in permanent quarters or temporary quarters.	OOC recommends that BSEE delete this line item from the proposed rule.
250.868	Non-metallic piping You may use non-metallic piping, such as that made from	This statement is confusing in that the term "atmospheric" is used; however, the examples given at (a) and (d) indicate	OOC recommends revising the language to read: "You may use non-metallic piping, such as that made from

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	polyvinyl chloride, chlorinated polyvinyl chloride, and reinforced fiberglass only in atmospheric, primarily non-hydrocarbon service such as:	pressurized piping greater than atmospheric pressure. Typical freshwater piping in galleys and living quarters operates at +/- 75 psig and firewater systems piping operates at +/- 200 psig.	polyvinyl chloride, chlorinated polyvinyl chloride, and reinforced fiberglass only in lower pressure (< 270 psig), primarily non-hydrocarbon service such as:…”
250.870 (a)	<u>Time delays on pressure safety low (PSL) sensors.</u> You must apply industry standard Class B, Class C, and Class B/C logic to all applicable PSL sensors installed on process equipment, as long as the time delay does not exceed 45 seconds. Use of a PSL sensor with a time delay greater than 45 seconds requires BSEE approval of a request under § 250.141. You must document on your field test records use of a PSL sensor with a time delay greater than 45 seconds. For purposes of this section, PSL sensors are categorized as follows: (1) Class B safety devices have logic that allows for the PSL sensors to be bypassed for a fixed time period (typically less than 15 seconds, but not more than 45 seconds). Examples include sensors used in conjunction with the design of pump and compressor panels such as PSL sensors, lubricator no-flows, and high-water jacket temperature shutdowns. (2) Class C safety devices have logic that allows for the PSL sensors to be bypassed until the component comes into full service (*i.e.*, the time at which the startup pressure equals or exceeds the set pressure of the PSL sensor, the system reaches a stabilized pressure and the PSL sensor clears). (3) Class B/C safety devices have logic that allows for the PSL sensors to incorporate a combination of Class B and Class C circuitry. These devices are used to ensure that the PSL sensors are not unnecessarily bypassed during start-up and idle operations, *e.g.*, Class B/C bypass circuitry activates when a pump is shut down during normal operations. The PSL sensor remains bypassed until the pump’s start circuitry is activated	PSL sensors should not be required to have timed or pressure build-up bypasses for startup activities. As written, it is also implied that all three industry standard Class logics must be applied simultaneously. Therefore it is recommended that the first sentence be reworded as follows: “You may apply industry standard Class B, Class C, or Class B/C logic to applicable PSL sensors installed on process equipment…” The established time frame of 45 seconds also seems unreasonable during a startup scenario and could cause startup operations to be unnecessarily rushed. We recommend that time delay be extended to several minutes to account for this.	OOC recommends revising the language to read: ““You may apply industry standard Class B, Class C, or Class B/C logic to applicable PSL sensors installed on process equipment…”

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	and either (i) The Class B timer expires no later than 45 seconds from start activation or (ii) The Class C bypass is initiated until the pump builds up pressure above the PSL sensor set point and the PSL sensor comes into full service.		
250.872(a)	Atmospheric Tanks You must equip atmospheric vessels used to process and /or store liquid hydrocarbons or other Class I liquids as described in API RP 500 or 505 (both incorporated by reference as specified in § 250.198) with protective equipment identified in API RP 14C, section A.5 (incorporated by reference as specified in § 250.198).	Is the intent to include non-permanent storage of chemicals and other substances used for ancillary operations such as well work, painting, etc.? Compliance would be difficult since many products are stored in transporters, drums and buckets. Inclusion of devices such as LSH would serve no useful purpose and do not have a "source" to shut in, with hookup to facility safety systems a major burden since these are moved frequently. Requirement for venting and/or flame arrestors for drums and transporters is understandable, requiring full compliance with API 14C atmospheric vessel requirements will impose additional burdens that provide no tangible benefits.	OOC recommends revising the language to specifically exclude tanks (DOT approved transport tanks, etc.) from this requirement by adding the following sentences to the end of this paragraph: “Tanks that are not connected, via interconnect piping, to the production process train and are used for storage only of refined liquid hydrocarbons or Class I liquids are not required to be equipped with the protective equipment identified in API RP 14C, section A.5 except for the appropriate TSE coverage. You must ensure that these storage tanks are protected by adequate containment to prevent the unauthorized discharge of the contents into the OCS waters.”
250.872(b)	Atmospheric Tanks You must ensure that all atmospheric vessels are designed and maintained to ensure the proper working conditions for LSH sensors. The LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality. For atmospheric vessels that have oil buckets, the LSH sensor must be installed to sense the level in the oil bucket.	What is BSEE’s justification for this far-reaching requirement? This will have a huge impact for manufactured "standard" designs currently in service that do not have nozzles for moving level sensors. Potential exposure to additional safety risk in refitting so many components. Placing LSH in oil bucket may not necessarily reduce risk of pollution, depending on individual equipment design. Many are configured for the oil bucket level to be much lower than the main compartment level so LSH in oil bucket would not sense true "high" level in the component, requiring two LSHs to be installed rather than just relocating the LSH. It will be difficult to retrofit vessel oil buckets with a LSH sensor if they do not have the appropriate nozzles. Will exceptions be	OOC recommends revising the language to read: “You must ensure that all atmospheric vessels are designed and maintained to ensure the proper working conditions for LSH sensors. The LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality. For new atmospheric vessels that have oil buckets and wherever practical on existing atmospheric vessels, the LSH sensor must be installed to sense the level in the oil bucket.”

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
		made for existing equipment currently in service?	
250.873 (b)(1)	Subsea gas lift requirements Additional requirements (i) Ensure that the MAOP of a subsea gas lift supply pipeline is equal to the MAOP of the production pipeline. An actuated fail-safe close gas-lift isolation valve (GLIV) located at the point of intersection between the gas lift supply pipeline and the production pipeline, pipeline riser, or manifold. (ii) Install an actuated fail-safe close gas-lift isolation valve (GLIV) located at the point of intersection between the gas lift supply pipeline and the production pipeline, pipeline riser, or manifold. Install the GLIV downstream of the underwater safety valve(s) (USV) and/or AIV(s).	The tables in 30CFR250. 873, 874 and 875 are not consistent with the tables issued in NTLs and guidance provided via DWOP approvals and discussions with BSEE GOM Region's TAS - reference document titled NTL 2011-N11 Subsea Pumping for Producing Operations Considerations for Using Subsea Gas Lift and Water Flood as Secondary Recovery Methods for Production Operations" attached------- recommend BSEE revisit and revise as per NTL 2011-N11 and previous guidance (aforementioned guidance document) issued to operators. See OOC Attachments #5 and #6	OOC recommends that BSEE update the table to be in alignment with the published tables in the NTL
250.875 a -e	Subsea Pump Systems. Follow the subsea pump testing requirements by: (1) Performing a complete subsea pump function test, including full shutdown after any intervention, or changes to the software and equipment affecting the subsea pump; and (2) Testing the subsea pump shutdown including PSHL sensors both upstream and downstream of the pump each quarter, but in no case more than 120 days between tests. This testing may be performed concurrently with the ESD function test.	The tables in the NPR have changed from previous guidance provided in DWOP via BSEE GOM Region's TAS Considerations for Using Subsea Gas Lift and Water Flood as Secondary Recovery Methods for Production Operations -------Revisit and revise as previous guidance issued to operators Proposed rule does not provide valve closure timing table which is provided as Table 1 in NTL 2011-N11. Recommend this table be included as part of this regulation to avoid confusion during DWOP approval process. This Loss of Communications case is provided in NTL 2011-N11 but now proposal does not provide details of how or if immediate shutdown of well or subsea boost system is to be executed. Recommend further clarity be provided in proposed regulation as to shutdown sequence/timing expected.	OOC recommends that the proposed rule tables align with the tables published in the current NTLs since BSEE is attempting to codify the existing NTLs.

Attachment 1 – OOC Detailed Comments on Subpart H Proposed Rule

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
250.876	<u>Fired and Exhaust Heated Components.</u> Every 5 years you must have a qualified third party remove, inspect, repair, or replace tube-type heaters that are equipped with either automatically controlled natural or forced draft burners installed in either atmospheric or pressure vessels that heat hydrocarbons and/or glycol. If removal and inspection indicates tube-type heater deficiencies, you must complete and document repairs or replacements. You must document the inspection results, retain such documentation for at least 5 years, and make them available to BSEE upon request.	BSEE needs to clarify the requirement to remove the fire tube to inspect and clarify the ""Qualified Third Party"". Many fire tubes are inaccessible and require lift-boats or rental cranes to access the fire tubes. Vessels must be cleaned to remove the fire tubes. This presents uncommon hazards to personnel when there are alternative methods for conducting inspection of the fire tube. The first sentence should be clarified to state that fired and exhaust heated components may be inspected in place. Having to remove the components for inspection will be a potential safety hazard as well as a very costly requirement and will not add material value to the inspection process. Additionally, BSEE has not fully evaluated the impact on existing components. By requiring "qualified third party(s)," and not specifying the timeframe for which to complete these inspections, BSEE will create an immediate shortage of these qualified parties. BSEE severely underestimated the economic impact to industry. OOC estimates that it will cost $30,000-$60,000 per fired vessel. This includes equipment, boat, and service hands. This estimate does not include lost production. The cost may exceed these estimates if a jack-up vessel is required. Some cannot be reached by crane Further, there should not be a specific inspection interval for fired components of pressure or atmospheric vessels. The fired component should be inspected, when required, by the governing code at the same interval as the host equipment.	OOC recommends revising the language to read: " Fired and exhaust heated components must be inspected by appropriate techniques capable of detecting degradation, at the same interval as the host vessel not exceed 10 years, unless you use a risk based inspection program and you can show justification for exceeding the 10 year period.
250.880 (c)(2)(v)	<u>Production safety system testing.</u> FSVs. Testing frequency and requirements Once each calendar month, not to exceed 6 weeks between tests. All FSVs must be tested, including those installed on a	Given that the referenced table in 14C speaks only to "Flowline Check Valve (FSV), it appears that the propose language has a typographical error in that the proposed language is missing the word "flowline." This would be the case unless BSEE is identifying on the flowline check valve by using the designation	OOC recommends inserting the word "flowline" into the sentence in front of the acronym FSV.

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	host facility in lieu of being installed at a satellite well. You must test FSVs for leakage in accordance with the test procedure specified in API RP 14C, appendix D, section D4, table D2 subsection D (incorporated by reference as specified in § 250.198). If leakage measured exceeds a liquid flow of 400 cubic centimeters per minute or a gas flow of 15 cubic feet per minute, the FSV must be repaired or replaced.	"FSV" in proposed language.	
250.880(c)(3)(i)	The following testing requirements apply to surface safety systems and devices: Pumps for firewater systems.	A reference to an inspection requirement has now been added which is not included in the existing regulations. Previously, pumps were required to run and tested weekly for operation and pressure delivery (two hose streams while maintaining 75 psig on the system). This new requirement now adds an annual inspection for pump performance (flow volume and delivery pressure) to ensure the pump system satisfies the system design requirements. BSEE has not identified the rationale for this added inspection item nor have the identified the benefit of this inspection item above the existing inspection criteria.	OOC recommends that this section be deleted in its entirety from the proposed rule until BSEE has fully evaluated the content of 14G and the value of this requirement.
250.880 (c)(3)(iv)	<u>Production safety system testing.</u> Item name TSH devices. Testing frequency and requirements Must be tested for operation at least once every 12 months, excluding those addressed in paragraph (b)(3)(v) of this section and those that would be destroyed by testing. Those that could be destroyed by testing must be visually inspected and the circuit tested for operations at least once every 12 months.	This appears to be a typographical error. OOC assumes that this should read " Must be tested for operation at least once every 12 months, excluding those addressed in paragraph (c)(3)(v) of this section and those that would be destroyed by testing. Those that could be destroyed by testing must be visually inspected and the circuit tested for operations at least once every 12 months.	OOC recommends correcting the citation to reference (c)(3)(v).
250.880(c)(5)(i)	The following testing and other requirements apply to subsea wells shut-in and disconnected from monitoring capability for periods greater than 6 months: Each well must be left with three pressure barriers: a closed and tested surface-controlled SSSV, a closed and tested USV,	While OOC agrees with the 3-barrier concept. Not all subsea wells may have been equipped with more than one USV or an additional tree valve that can serve in this capacity.	OOC recommends revising the language to read: "Each well must be left with three pressure barriers to include at least a closed and tested surface-controlled SSSV and a closed and tested USV."

Reference	BSEE Proposed Rule Language	OOC Comments	OOC Recommended Language
	and one additional closed and tested tree valve.		
250.880(c)(5)(ii)(B)	The USV and other pressure barrier must be tested to confirm zero leakage.	Not all existing subsea wells may be able to meet this requirement, since some tree valves are typically allowed some leakage volume during testing. These leakage rates are typically part of the approved DWOP and the specific conditions of approval of the DWOP such as the leakage rate for the BSDV from subsea wells.	OOC recommends revising the language to read: " §250.880 (c)(5)(ii)(B) The USV and other pressure barrier must be tested to confirm that, as a group, the valves allow zero leakage."
250.880 (c)(5) (v)	<u>Production safety system testing.</u> The following testing and other requirements apply to subsea wells shut-in and disconnected from monitoring capability for periods greater than 6 months: … (v) A drilling vessel capable of intervention into the disconnected well must be in the field or readily accessible for use until the wells are brought on line.	This is confusing in its current language and seems excessive since BSEE has not identified the need for having a drilling vessel "readily available" or "in the field." OOC suggests that BSEE clarify the intent of this proposed rule. OOC also suggests that in (c)(5)(v), BSEE clarify the definition of "in the field or readily accessible." BSEE should consider that rigs should not have to be under direct contract to be considered "readily accessible." It is also unclear under what circumstances a "drilling vessel" would be required to intervene in a shut-in well that is disconnected from monitoring capability. Maintaining a rig on standby would not be cost-effective.	OOC recommends revising the language to read: " §250.880 (c)(5)(v) The designated operator/lessee must ensure that a drilling vessel capable of intervention into the disconnected well must be available to the operator for use should the need arise until the wells are brought on line."
250.891	Safety Device Training You must ensure that personnel installing, repairing, testing, maintaining, and operating surface and subsurface safety devices and personnel operating production platforms, including but not limited to separation, dehydration, compression, sweetening, and metering operations, are trained in accordance with the procedures in subpart S of this part.	While OOC recognizes the intent of moving from the Subpart O requirements to Subpart S with respect to training, OOC believes that Subpart O is still valid since it officially has not been withdrawn from the regulations. Further, Subpart O offers more detail into the training program requirements and is an established platform that all operators use as the basis for Production Safety Systems and Well Control Training programs. Also, as written (and ignoring the existing language in Subpart O) BSEE is imposing detailed requirements on the operator that are not specifically required in Subpart S nor or they recommended in API RP 75	OOC recommends that this language should be revised to reflect Subpart O and not Subpart S. Until BSEE is ready to withdraw Subpart O in its entirety, the existing regulations should still reference Subpart O.