January 29, 2018

Submitted via www.regulations.gov

Ms. Amy White
Department of the Interior
Bureau of Safety and Environmental Enforcement
Attention: Regulations Development Branch
45600 Woodland Road, VAE-ORP
Sterling, VA 20166

RE: Joint Trades Comments
Oil and Gas Production Safety Systems-Revisions, 1014-AA37
Docket Number: BSEE-2017-0008

The American Petroleum Institute (API), the Offshore Operators Committee (OOC) and the National Ocean Industries Association (NOIA), hereinafter referred to as the Joint Trades, appreciate the opportunity to provide comments on the Bureau of Safety and Environmental Enforcement's (BSEE) *Oil and Gas and Sulphur Operations on the Outer Continental Shelf – Oil and Gas Production Safety Systems – Revisions* (*Federal Register*, Volume 82, Number 249, December 29, 2017) – (hereinafter referred to as "the Production Safety Systems Rule" or "the rule").

The Joint Trades

API is a national trade association representing more than 625 member companies involved in all aspects of the oil and natural gas industry. API's members include producers, refiners, suppliers, pipeline operators, marine transporters, and service and supply companies that support all segments of the industry. API and its members are dedicated to meeting safety and environmental requirements, while economically and safely developing and supplying energy resources for consumers.

The OOC is an offshore oil and natural gas trade association that serves as a technical advocate for companies operating in the Gulf of Mexico (GOM). Founded in 1948, the OOC has evolved into the principal technical representative regarding regulation of offshore oil and natural gas exploration, development, and producing operations. The OOC's member companies are responsible for approximately 90% of the oil and natural gas production from the GOM.

NOIA is the only national trade association representing all segments of the offshore industry with an interest in the exploration and production of both traditional and renewable energy resources on the US Outer Continental Shelf (OCS). The NOIA membership comprises more than 325 companies engaged in a variety of business activities, including production, drilling, engineering, marine and air transport, offshore construction, equipment manufacture and supply, telecommunications, finance and insurance, and renewable energy.

Joint Trades Comments and Recommendations

US OCS production is vitally important to our nation's energy security and our nation's economy. Safety in OCS operations is a core value of the energy industry, and a value that our members put into practice each day. Therefore, the Production Safety Rule is significant because it forms the foundation by which oil and natural gas are safely and efficiently produced from the OCS.

The comments contained in this submittal are provided as recommendations to improve the proposed Production Safety Systems Rule as well as inform BSEE of potential obstacles and impacts from the revisions to the rule. The Joint Trades comments are offered without prejudice to any of our members who may have differing or opposing views.

1. The Joint Trades support several of the proposed changes

The Joint Trades support several changes proposed in the Production Safety Systems Rule. Regulatory reforms, such as reducing the number of items requiring a professional engineering seal, the elimination of certain independent third-party reviews, and alternatives for heater tube inspections, provide a more logical and efficient approach to safety requirements. For example, the current Production Safety Systems Rule requires an independent third-party review of valves that were already required to be designed and manufactured according to API Specification Q1, *Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry*. The independent third-party review did not add value or improve safety.

As BSEE explained in the preamble to the proposed revisions, these types of common sense regulatory reforms are well aligned with the requirements of Executive Order 13771 (EO 13771), *Reducing Regulation and Controlling Regulatory Costs*, and similar reforms should continue to be a focus for BSEE and all DOI agencies moving forward.

As detailed in Appendix 1, The Joint Trades have noted support for several of the proposed changes.

2. The Joint Trades have identified opportunities for additional regulatory reform improvements to the rule

The preamble to the rule requests feedback and comments on many issues which were raised by industry following the release of the 2016 Production Safety Systems final rule.

Although the proposed Production Safety Systems Rule includes several enhancements, BSEE has an opportunity to make further changes that would eliminate additional unnecessary regulatory burdens. Since September 2016, the offshore industry has discussed on multiple occasions many of these unnecessary burdens with BSEE. We appreciate that in the preamble to the December 2017 proposed revisions BSEE has asked for comments on many of these issues, but BSEE could have proposed regulatory language for review.

For example, industry noted that in the 2016 final rule, BSEE did not include any clarifications or modifications to the definition of “failure” of Safety and Pollution Prevention Equipment (SPPE). The industry needs clarity on the types of events that are considered SPPE failures and has attempted to clarify that definition since September 2016. At a Production Safety Systems forum held in New Orleans in March 2017, industry proposed an alternate definition of SPPE “failure” that provides additional specificity. At that time, BSEE did not entertain the alternative definition. With Appendix 2 of the Joint Trades comment letter, we have expanded upon our justification for why the alternative definition is critical and would promote consistent and meaningful reporting of SPPE failures.

As described in both Appendix 1 and 2, the Joint Trades are recommending a definition of failure that aligns with industry standards. In addition, we are strongly encouraging more dialogue on this issue, and are recommending a workshop (or series of workshops) to identify potential solutions for reporting SPPE failures.

A second important improvement opportunity area that has been raised since September 2016 relates to the testing requirements for pressure safety valves (PSVs). As with failure reporting, the agency and offshore operators have held numerous discussions regarding the implementation challenges, costs, and risks resulting from the requirement to conduct an annual PSV test where the main valve piston must be lifted. Over the last year, industry has presented alternative methods of testing, and has included those recommendations in these comments (see Appendices 1 and 2).

In addition to these improvement opportunities, the Joint Trades have provided feedback to BSEE’s request for comments on other specific issues in Appendix 2.

3. Sufficient time for a complete review of the rule’s revisions has not been provided

The comments contained in this submittal represent industry’s best effort to provide meaningful feedback in the time provided, and the Joint Trades believe that many of the comments included herein are important and meaningful (See Appendices). However, much more valuable information could have been provided to BSEE had additional time been allocated for the comment period.

4. Sufficient time must be given for implementation of the final rule

Allotting sufficient time to implement the final rule is crucial to achieving compliance success. The proposed revisions to the rule are silent on the timing allowed for implementation of any final rule requirements. It is critical that BSEE fully understand the implications of what they will be tasking both industry and their own resources in undertaking and plan the implementation of the rule accordingly.

A sound approach would be to evaluate each change and determine appropriate compliance deadlines based on the magnitude of the change, the time required for BSEE to train its staff on the new requirements, the time required for operators to train and communicate the new requirements, and the need to make physical changes to the approximately 2400 offshore production facilities.

For example, the proposed changes to documents that require a professional engineering seal is relatively straightforward as they require no physical changes to facilities and can likely be implemented quickly (e.g. within 60 days from publication). However, the proposed change in 30 CFR 250.198 to incorporate the 8th Edition of API Recommended Practice 14C (API RP 14C) will have additional impacts that will require a longer implementation timeframe. The Joint Trades have included comments and concerns regarding API RP 14C in Appendix 3.

The minimal amount of time industry was allocated to implement the current Production Safety Systems rule published in September 2016 resulted in numerous requests to BSEE for alternate approaches to achieve compliance. BSEE must take steps to ensure that a similar situation does not occur again. The Joint Trades are very interested in providing recommendations to BSEE on appropriate implementation timelines for the proposed changes to the rule, but, as discussed earlier, more time than the allotted 30-day comment period is needed to develop this type of input.

5. Application of new editions of documents incorporated by reference to existing equipment

BSEE must ensure that existing equipment designed, constructed and installed in accordance with codes and standards pre-dating the standards proposed for incorporation by reference in 30 CFR 250.198 are not adversely affected. Implementation of new codes and standards should be applicable only to new equipment designed, constructed and installed after the effective date of the final rule. In short, new standards should not be applied to existing equipment designed to previous codes. This approach is common in other regulatory programs and should be a practice adopted by BSEE.

6. Detailed comments and responses to BSEE's requests are included in the attachments

Attached to this letter are three appendices containing detailed comments on the proposed revisions to the Production Safety Systems Rule.

- Appendix 1 contains comments and suggested changes to the text of the proposed rule on a section-by-section basis.
- Appendix 2 contains responses to the items BSEE solicited input on in the preamble to the proposed rule.
- Appendix 3 contains comments and issues related to incorporating by reference API RP 14C.

Effective safety systems are critical to offshore oil and natural gas operations. It is also important that the regulations governing offshore safety be technically-sound, implementable and efficient. The Joint Trades fully support BSEE's efforts to eliminate burdensome regulatory requirements which do not provide meaningful safety improvements. We also strongly recommend that BSEE consider the comments contained in this submittal to further improve offshore safety and efficiency.

If you have any questions or would like to discuss the Joint Trades comments in more detail, please contact Greg Southworth, OOC, at greg@offshoreoperators.com or Holly Hopkins, API, at hopkinsh@api.org.

Sincerely,

Erik Milito
Group Director, Upstream & Industry Operations
American Petroleum Institute

Evan Zimmerman
Executive Director
Offshore Operators Committee

Randall Luthi
President
National Ocean Industries Association

cc: Joe Balash, Assistant Secretary for Land and Minerals Management, US Department of the Interior
Katharine MacGregor, Deputy Assistant Secretary for Land and Minerals Management, US Department of the Interior
Scott Angelle, Director, Bureau of Safety and Environmental Enforcement
Lars Herbst, Director, Gulf of Mexico Region, Bureau of Safety and Environmental Enforcement
Doug Morris, Chief, Office of Offshore Regulatory Programs, Bureau of Safety and Environmental Enforcement

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
§ 250.107(a)(3)	(a) You must protect health, safety, property, and the environment by: (1) Performing all operations in a safe and workmanlike manner; (2) Maintaining all equipment and work areas in a safe condition; (3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and (4) Complying with all lease, plan, and permit terms and conditions.	*****	*Although 30 CFR 250.107 (a)(3) was not specifically identified in BSEE's notice for comment, Industry strongly recommends that the phrase "to the lowest level practicable" be deleted from 30 CFR 250.107(a)(3) because: (1) it creates a contrary requirement to the BAST provision of 30 CFR 250.107 (c), (2) it was promulgated without a justification, cost-benefit, or burden analysis, (3) it unjustifiably exceeds existing and sufficient safety regulations, and (4) it runs contrary to the BAST regulatory standard specified in the Outer Continental Shelf Lands Act (OCSLA).* *(1) In April 2016, BSEE issued a final rule for Oil and Gas and Sulfur Operations in the Outer Continental Shelf-Blowout Preventer Systems and Well Control Rule, being published in 81 Fed. Reg. 25888 and codified in 30 CFR Part 250 (hereafter, "Well Control Rule").* *In September 2016, BSEE issued a final rule for Oil and Gas and Sulfur Operations on the Outer Continental Shelf-Oil and Gas Production Safety Systems, being published in 81 Fed. Reg. 61833 and codified in 30 CFR Part 250 (hereafter, "Production Safety Systems Rule").* *Whereas the Production Safety Systems Rule included language clarifying the longstanding a Best Available and Safest Technology standard in*

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			30 CFR 250.107(c) ("BAST"), the earlier Well Control Rule promulgated a contrary, undefined, and highly uncertain 'lowest level practicable' standard in 30 CFR 250.107(a)(3)) ("LLP"). Although BAST allows for a waiver for existing operations, LLP broadly applies to all OCS operations - both new and existing – without any provision for waiver (i.e. "…reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities"). Therefore, LLP and BAST are not consistent. *Furthermore, BSEE has not provided guidance as to what regulations or standards represent compliance with LLP; in contrast, the BAST rule specifically says that conformance with BSEE regulations is presumed to constitute use of BAST (see 30 CFR 250.107(c)(2)). Consequently, operators with comprehensive, effective safety-management systems and outstanding compliance records are now exposed to vague and possibly frivolous challenges regarding whether their systems conform to the regulatory LLP standard. As the regulator, BSEE is also subject to similar vagueness challenges as it tries to enforce these two, incongruent risk-reduction standards.* *Thus, the contradictory regulations place both Industry and BSEE in an untenable compliance position.*

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			(2) In promulgating the LLP standard, BSEE failed to provide a specific cost-justification for the proposed change, a cost-benefit assessment, or a burden analysis. These regulatory impact analyses are required by, among other things, Executive Order 12866 and OMB Circular A-4. *(3) BSEE has presented no data indicating that LLP adds any significant safety benefit, yet the vague LLP standard burdens companies with unnecessary and uncertain compliance challenges. The performance standards contained throughout the regulations –such as 30 CFR 250.107(a)(1), (b), and (c) of Subpart A and all of Subpart S – are more than sufficient to ensure effective safety and risk management. Therefore, eliminating LLP would be consistent with Executive Order 13771.* *(4) Lastly, the Outer Continental Shelf Lands Act explicitly requires a 'Best Available and Safest Technology' standard for any 'safety and health regulations' promulgated under the act. LLP neither conforms to, nor is consistent with, this statutorily-mandated standard (see 43 U.S.C. 1347).* *For the reasons stated above, the Joint Trades strongly recommend BSEE revise 30 CFR §250.107(a)(3) to read as follows:*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			Utilizing recognized engineering practices that reduce risks ~~to the lowest level practicable~~ when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and
§ 250.107(c)	(c) *Best available and safest technology.* (1) On all new drilling and production operations and, except as provided in paragraph (c)(3) of this section, on existing operations, you must use the best available and safest technologies (BAST) which the Director determines to be economically feasible whenever the Director determines that failure of equipment would have a significant effect on safety, health, or the environment, except where the Director determines that the incremental benefits are clearly insufficient to justify the incremental costs of utilizing such technologies. (2) Conformance with BSEE regulations will be presumed to constitute the use of BAST unless and until the Director determines that other technologies are required pursuant to paragraph (c)(1) of this section. (3) The Director may waive the requirement to use BAST on a category of existing operations if the Director determines that use of BAST by that category of existing operations would not be practicable. The Director may waive the requirement to use BAST on an existing operation at a specific facility if you submit a waiver request demonstrating that the use of BAST would not be practicable.	*****	*While the current language at 250.107(c)(2) is straightforward in that compliance with the regulations is presumed to constitute the use of BAST, we are more concerned with the BAST Determination Process. The determination process, in its current form, appears to allow BSEE to require compliance with "new" BAST without BSEE following the rulemaking process.* *In the event that BSEE determines that a new BAST Determination may be necessary, the agency may initiate the BAST Determination Process. The BAST Determination process consists of 3 main stages: (1) BAST Assessment and Initial Feasibility, (2) BAST Evaluation, and (3) BAST Determination. Each of these stages includes certain milestones and public notices; however, it is imperative that each stage, milestone, and public notice start with publication in the Federal Register allowing for stakeholder comment, thus ensuring transparency. Following such a process allows for publication of the problem statement along with supporting data for public review, analysis, and comments. Further, the Agency must publish for notice and comment its proposed action prior to issuing a final BAST determination. Additionally, BSEE must go*

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			through a full rulemaking process prior to mandating the use of any new technology on the OCS as a result of the BAST Determination Process. The failure of BSEE to include the rulemaking process (ANPRM, NPRM, FRM) in the BAST Determination Process, circumvents BSEE's requirement to allow for public review and comment, and BSEE's obligations to address those comments prior to issuing a final rule.
§ 250.198 Documents incorporated by reference	(a)-(f) (a) The BSEE is incorporating by reference the documents listed in paragraphs (e) through (k) of this section. Paragraphs (e) through (k) identify the publishing organization of the documents, the address and phone number where you may obtain these documents, and the documents incorporated by reference. The Director of the Federal Register has approved the incorporations by reference according to 5 U.S.C. 552(a) and 1 CFR part 51.	*****	*250.198(a) says documents listed in paragraphs (e) through (k) are incorporated by reference. Documents are listed from paragraph (e) through (n). Therefore, the following change is recommended:* *(a) The BSEE is incorporating by reference the documents listed in paragraphs (e) through ~~(k)~~ (n) of this section. Paragraphs (e) through ~~(k)~~ (n) identify the publishing organization of the documents, the address and phone number where you may obtain these documents, and the documents incorporated by reference. The Director of the Federal Register has approved the incorporations by reference according to 5 U.S.C. 552(a) and 1 CFR part 51.*
	(g) (1) ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices, 2004 Edition; and July 1, 2005 Addenda, and all Section I Interpretations Volume 55, incorporated by reference at §§ 250.851(a)(1)(i), (a)(4)(iii), (a)(5)(i), and 250.1629(b)(1), (b)(1)(i).	ANSI/ASME Boiler and Pressure Vessel Code, Section I, Rules for Construction of Power Boilers; including Appendices, 2017 Edition; and July 2017 Addenda, and all Section I Interpretations Volume 55, incorporated by reference at §§ 250.851(a), and 250.1629(b).	*The Joint Trades support the proposed change. However, while it is understood that all ASME coded vessels must bear legible code-stamped nameplates by the specified deadline, it should be clarified that existing vessels need not be modified to satisfy new requirements specified in the latest*

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			editions of the ASME BPVC. The latest code editions should apply to fabrication of new vessels only.
	(2) ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers; including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2004 Edition; July 1, 2005 Addenda, and all Section IV Interpretations Volume 55, incorporated by reference at §§ 250.851(a)(1)(i), (a)(4)(iii), (a)(5)(i), and 250.1629(b)(1), (b)(1)(i).	ANSI/ASME Boiler and Pressure Vessel Code, Section IV, Rules for Construction of Heating Boilers; including Appendices 1, 2, 3, 5, 6, and Non-mandatory Appendices B, C, D, E, F, H, I, K, L, and M, and the Guide to Manufacturers Data Report Forms, 2017 Edition; July 2017 Addenda, and all Section IV Interpretations Volume 55, incorporated by reference at §§ 250.851(a) and 250.1629(b).	*The Joint Trades support the proposed change. However, while it is understood that all ASME coded vessels must bear legible code-stamped nameplates by the specified deadline, it should be clarified that existing vessels need not be modified to satisfy new requirements specified in the latest editions of the ASME BPVC. The latest code editions should apply to fabrication of new vessels, only.*
	(3) ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2004 Edition; July 1, 2005 Addenda, Divisions 1, 2, and 3 and all Section VIII Interpretations Volumes 54 and 55, incorporated by reference at §§ 250.851(a)(1)(i), (a)(4)(iii), (a)(5)(i), and 250.1629(b)(1), (b)(1)(i).	ANSI/ASME Boiler and Pressure Vessel Code, Section VIII, Rules for Construction of Pressure Vessels; Divisions 1 and 2, 2017 Edition; July 2017 Addenda, Divisions 1, 2, and 3 and all Section VIII Interpretations Volumes 54 and 55, incorporated by reference at §§ 250.851(a) and 250.1629(b).	*The Joint Trades support the proposed change. However, while it is understood that all ASME coded vessels must bear legible code-stamped nameplates by the specified deadline, it should be clarified that existing vessels need not be modified to satisfy new requirements specified in the latest editions of the ASME BPVC. The latest code editions should apply to fabrication of new vessels, only.*
	(h) (1) API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Ninth Edition, June 2006, Product No. C51009; incorporated by reference at §§ 250.851(a)(1)(ii) and 250.1629(b)(1);	API 510, Pressure Vessel Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, Downstream Segment, Tenth Edition, May 2014; Addendum 1, May 2017; incorporated by reference at §§ 250.851(a) and 250.1629(b);	*The Joint Trades support the proposed change.*
	(h)		
	(51) API RP 2RD, Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; reaffirmed, May 2006, Errata, June 2009; Order No.	API STD 2RD, Dynamic Risers for Floating Production Systems, Second Edition, September 2013; incorporated by reference at §§ 250.292, 250.733, 250.800(c), 250.901(a), (d), and 250.1002(b);	*In general, the Joint Trades support the proposed change. However, timing for implementation of the new standard must be clarified, especially for those facilities that are currently under*

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	G02RD1; incorporated by reference at §§ 250.800(c)(2), 250.901(a), (d), and 250.1002(b)(5);		*construction at the time of the effective date of the final rule.*
	(52) API RP 2SK, Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008, Product No. G2SK03; incorporated by reference at §§ 250.800(c)(3) and 250.901(a), (d);	API RP 2SK, Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures, Third Edition, October 2005, Addendum, May 2008, Reaffirmed June 2015; incorporated by reference at §§ 250.800(c) and 250.901(a) and (d);	*The Joint Trades support the proposed change.*
	(53) API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, First Edition, March 2001, Addendum, May 2007; incorporated by reference at §§ 250.800(c)(3) and 250.901;	API RP 2SM, Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring, Second Edition, July 2014; incorporated by reference at §§ 250.800(c) and 250.901;	*In general, the Joint Trades support the proposed change. However, timing for implementation of the new standard must be clarified, especially for those facilities that are currently under construction at the time of the effective date of the final rule.*
	(55) API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, ANSI/API Recommended Practice 14B, Fifth Edition, October 2005, also available as ISO 10417: 2004, (Identical) Petroleum and natural gas industries—Subsurface safety valve systems—Design, installation, operation and redress, Product No. GX14B05; incorporated by reference at §§ 250.802(b), 250.803(a), 250.814(d), 250.828(c), and 250.880(c)(1)(i), (c)(4)(i), (c)(5)(ii)(A);	ANSI/API RP 14B, Recommended Practice for Design, Installation, Repair and Operation of Subsurface Safety Valve Systems, Sixth Edition, September 2015; incorporated by reference at §§ 250.802(b), 250.803(a), 250.814(d), 250.828(c), and 250.880(c);	*The Joint Trades support the proposed change.*
	(56) API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms, Seventh Edition, March 2001, Reaffirmed: March 2007; Product No. C14C07; incorporated by reference at §§ 250.125(a)(10), 250.292(j), 250.841(a), 250.842(a)(2), 250.850, 250.852(a)(1), 250.855, 250.858(a), 250.862(e), 250.867(a), 250.869(a)(3), (b), (c),	API RP 14C, Recommended Practice for Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities, Eight Edition, February 2017; incorporated by reference at §§ 250.125(a), 250.292(j), 250.841(a), 250.842(a), 250.850, 250.852(a), 250.855, 250.856(a), 250.858(a), 250.862(e), 250.865(a), 250.867(a), 250.869(a) through (c), 250.872(a), 250.873(a), 250.874(a),	*The Joint Trades do not recommend the incorporation of the 8th Edition API RP 14C at this time. Industry needs additional time to fully understand and implement the changes contained in the 8th Edition. In addition, it is also important for BSEE staff to fully understand the changes contained in the 8th Edition. We have included a*

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	250.872(a), 250.873(a), 250.874(a), 250.880(b)(2), (c)(2)(v), 250.1002(d), 250.1004(b)(9), 250.1628(c), (d)(2), 250.1629(b)(2), (b)(4)(v), and 250.1630(a);	250.880(b) and (c), 250.1002(d), 250.1004(b), 250.1628(c) and (d), 250.1629(b), and 250.1630(a);	*more detailed analysis of potential concerns in the 8th Edition as Appendix 3 to this comment package.*
	(57) API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems, Fifth Edition, October 1991; Reaffirmed, March 2007, Order No. 811-07185; incorporated by reference at §§ 250.841(b), 250.842(a)(1), and 250.1628(b)(2), (d)(3);	*****	
	(58) API RP 14F, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations, Upstream Segment, Fifth Edition, July 2008, Product No. G14F05; incorporated by reference §§ 250.114(c), 250.842(b)(1), 250.862(e), and 250.1629(b)(4)(v);	API RP 14F, Recommended Practice for Design, Installation, and Maintenance of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities for Unclassified and Class 1, Division 1 and Division 2 Locations, Upstream Segment, Fifth Edition, July 2008, Reaffirmed: April 2013; incorporated by reference at §§ 250.114(c), 250.842(c), 250.862(e), and 250.1629(b);	*The Joint Trades support the proposed change.*
	(59) 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, First Edition, September 2001, Reaffirmed: March 2007; Product No. G14FZ1; incorporated by reference at §§ 250.114(c), 250.842(b)(1), 250.862(e), and 250.1629(b)(4)(v);	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, Second Edition, May 2013; incorporated by reference at §§ 250.114(c), 250.842(c), 250.862(e), and 250.1629(b);	*In general, the Joint Trades support the proposed change. However, timing for implementation of the new standard must be clarified, especially for those facilities that are currently under construction at the time of the effective date of the final rule.*
	(60) API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open-type Offshore Production Platforms, Fourth Edition, April 2007; Product No. G14G04; incorporated by reference at §§ 250.859(a), 250.862(e), and 250.1629(b)(3), (b)(4)(v);	API RP 14G, Recommended Practice for Fire Prevention and Control on Fixed Open- type Offshore Production Platforms, Fourth Edition, April 2008, reaffirmed January 2013; incorporated by reference at §§ 250.859(a), 250.862(e), 250.880(c), and 250.1629(b);	*The Joint Trades support the proposed change.*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	(61) API RP 14H, Recommended Practice for Installation, Maintenance and Repair of Surface Safety Valves and Underwater Safety Valves Offshore, Fifth Edition, August 2007, Product No. G14H05; incorporated by reference at §§ 250.820, 250.834, 250.836, and 250.880(c)(2)(iv), (c)(4)(iii);	API STD 6AV2, Installation, Maintenance, and Repair of Surface Safety Valves and Underwater Safety Valves Offshore; First Edition, March 2014; Errata 1, August 2014; incorporated by reference at §§ 250.820, 250.834, 250.836, and 250.880(c);	*In general, the Joint Trades support the proposed change. However, timing for implementation of the new standard must be clarified, especially for those facilities that are currently under construction at the time of the effective date of the final rule.*
	(62) API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; Reaffirmed: March 2007; Product No. G14J02; incorporated by reference at §§ 250.800(b), (c)(1), 250.842(b)(3),and 250.901(a)(14);	API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities, Second Edition, May 2001; Reaffirmed: January 2013; incorporated by reference at §§ 250.800(b) and (c), 250.842(c), and 250.901(a);	*The Joint Trades support the proposed change.*
	(65) API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Second Edition, November 1997; Errata August 17, 1998, Reaffirmed November 2002, API Stock No. C50002; incorporated by reference at §§ 250.114(a), 250.459, 250.842(a)(1), (a)(3)(i), 250.862(a), (e), 250.872(a), 250.1628(b)(3), (d)(4)(i), and 250.1629(b)(4)(i);	API RP 500, Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Division 1 and Division 2, Third Edition, December 2012; Errata January 2014, API Stock No. C50002; incorporated by reference at §§ 250.114(a), 250.459, 250.842(a), 250.862(a) and (e), 250.872(a), 250.1628(b) and (d), and 250.1629(b);	*Similar to our comments at 250.198(h)(56) regarding API RP 14C, more time is needed to fully evaluate the impacts of API RP 500, Third Edition before it becomes a mandatory document. Therefore, the Joint Trades recommend delaying the incorporation of API RP 500, Third Edition until a later date.*
	(68) ANSI/API Spec. Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Eighth Edition, December 2007, Effective Date: June 15, 2008, Addendum 1, June 2010, Effective Date: December 1, 2010; also available as ISO TS 29001:2007 (Identical), Petroleum, petrochemical and natural gas industries—Sector specific requirements—Requirements for product and service supply organizations, Effective Date: December 15, 2003, API Stock No. GQ1007; incorporated by reference at § 250.801(b), (c);	ANSI/API Specification Q1 (ANSI/API Spec. Q1), Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Ninth Edition, June 1, 2014; Errata, February 2014; Errata 2, March 2014; Addendum 1, June 2016; incorporated by reference at §§ 250.730, 250.801(b) and (c);	*The Joint Trades support the proposed change.*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	(70) API Spec. 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004, Effective Date: February 1, 2005; Contains API Monogram Annex as part of US National Adoption; also available as ISO 10423:2003 (Modified), Petroleum and natural gas industries—Drilling and production equipment— Wellhead and Christmas tree equipment; Errata 1, September 2004, Errata 2, April 2005, Errata 3, June 2006, Errata 4, August 2007, Errata 5, May 2009, Addendum 1, February 2008, Addendum 2, December 2008, Addendum 3, December 2008, Addendum 4, December 2008, Product No. GX06A19; incorporated by reference at §§ 250.802(a), 250.803(a), 250.873(b), (b)(3)(iii), 250.874(g)(2) and 250.1002 (b)(1), (b)(2);	ANSI/API Specification 6A (ANSI/API Spec. 6A), Specification for Wellhead and Christmas Tree Equipment, Twentieth Edition, October 2010; Addendum 1, November 2011; Errata 2, November 2011; Addendum 2, November 2012; Addendum 3, March 2013; Errata 3, June 2013; Errata 4, August 2013; Errata 5, November 2013; Errata 6, March 2014; Errata 7, December 2014; Errata 8, February 2016; Addendum 4: June 2016; Errata 9, June 2016; Errata 10, August 2016; incorporated by reference at §§ 250.730, 250.802(a), 250.803(a), 250.833, 250.873(b), 250.874(g), and 250.1002(b);	*The Joint Trades support the proposed change.*
	(71) API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, First Edition, February 1, 1996; reaffirmed January 2003, API Stock No. G06AV1; incorporated by reference at §§ 250.802(a), 250.833, 250.873(b) and 250.874(g)(2);	API Spec. 6AV1, Specification for Verification Test of Wellhead Surface Safety Valves and Underwater Safety Valves for Offshore Service, Second Edition, February 2013; incorporated by reference at §§ 250.802(a), 250.833, 250.873(b), and 250.874(g);	*The Joint Trades support the proposed change.*
	(73) ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, Eleventh Edition, October 2005, Effective Date: May 1, 2006; also available as ISO 10432:2004 (Identical), Petroleum and natural gas industries—Downhole equipment— Subsurface safety valve equipment, Product No. GX14A11; incorporated by reference at §§ 250.802(b) and 250.803(a)	ANSI/API Spec. 14A, Specification for Subsurface Safety Valve Equipment, 12th Ed. January 2015; Errata, July 2015; Addendum, June 2017; incorporated by reference at §§ 250.802(b) and 250.803(a);	*The Joint Trades support the proposed change.*
	(74) ANSI/API Spec. 17J, Specification for Unbonded Flexible Pipe, Third Edition, July 2008, Effective Date: January 1, 2009, Contains API Monogram Annex as part	ANSI/API Spec. 17J, Specification for Unbonded Flexible Pipe, Fourth Edition, May 2014; Errata 1, September 2016; Errata 2, May 2017; incorporated by	*The Joint Trades support the proposed change.*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	of US National Adoption; also available as ISO 13628-2:2006 (Identical), Petroleum and natural gas industries—Design and operation of subsea production systems—Part 2: Unbonded flexible pipe systems for subsea and marine application; Product No. GX17J03; incorporated by reference at §§ 250.852(e)(1), (e)(4), 250.1002(b)(4), and 250.1007(a)(4)(i)(D).	reference at §§ 250.852(e), 250.1002(b), and 250.1007(a).	
	(96) API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Third Edition, November 2009; incorporated by reference at §250.841(b).	(96) API 570 Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, Fourth Edition, February 2016; Addendum 1: May 2017; incorporated by reference at § 250.841(b).	*The Joint Trades support the proposed change.*
§ 250.801 Safety and pollution prevention equipment (SPPE) certification	(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. BSEE considers the following equipment to be types of SPPE:	*SPPE equipment.* 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. BSEE considers the following equipment to be types of SPPE:	
	(5)	Gas lift shutdown valves (GLSDV) and their actuators.	*The Joint Trades offer that GLSDVs in a departing application do not require adherence to the SPPE certification standards, leakage rates, and testing frequencies to the same extent as BSDVs, USVs, SSVs, or SCSSVs/SSCSSVs. These latter valves are held to these standards due to their criticality in protecting personnel and the environment, whereas a GLSDV is a different application using dry gas to aid in the flow assurance of well production. Furthermore:* • *GLSDV are installed in a departing capacity (direction of flow into the well). There is a check valve to prevent backflow.*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			• *There is no testing frequency or leakage rate requirements for GLSDV.* • *There is no mention of GLSDV in the 8th edition of API RP 14C.* • *There are no statistics or failure data to justify the proposed addition of GLSDV as SPPE.* *In addition, if the agency chooses to maintain GLSDVs, the Joint Trades recommend that BSEE clarify that GLSDV requirements apply to subsea systems only.*
§ 250.802 Requirements for SPPE	(a) All SSVs, BSDVs, and USVs and their actuators must meet all of the specifications contained in ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference as specified in § 250.198).	All SSVs, BSDVs, USVs, and GLSDVs and their actuators must meet all of the specifications contained in ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference as specified in § 250.198).	*As stated in our comment at 250.801, GLSDVs should not be considered SPPE. In addition, for the other equipment listed, SPPE for which a contract or purchase order that had been finalized by September 7, 2017 should be treated as "currently installed" equipment (i.e. grandfathered). Equipment in the manufacturing process or in inventory as of September 7, 2017 would have been designed and manufactured according to the previous requirements.* *BSEE/MMS set precedence like this back in 1988 when the original SPPE regulation was enacted that applied to USV, SSV, and Subsurface safety valves. See below the old 30CFR250.806 (b) Use of Non-certified SPPE* *"(1) Before April 1, 1988, you may continue to use and install noncertified SPPE if it was in your inventory as of April 1, 1988 and was included in a*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			list of noncertified SPPE submitted to BSEE prior to August 29, 1988. *(2) On or after April 1, 1988: You may not install additional noncertified SPPE; and when noncertified SPPE that is already in service requires offsite repair, remanufacturing, or hot work such as welding, you must replace it with certified SPPE."* *Therefore, the Joint Trades offer the following recommended regulatory language:* *All SSVs, BSDVs, USVs, ~~and GLSDVs~~ and their actuators must meet all of the specifications contained in ANSI/API Spec. 6A and API Spec. 6AV1 (both incorporated by reference as specified in § 250.198), according to the following:* *You may continue to use and install SPPE in your inventory as of November 7, 2016 and was included in a list submitted to BSEE by August 1, 2018. After November 7, 2016 all new or modified SPPE must meet all of the specifications contained in ANSI/API Spec. 6A and API Spec. 6AV1.*
	(b) All SSSVs and their actuators must meet all of the specifications and recommended practices of ANSI/API Spec. 14A and ANSI/API RP 14B, including all annexes (both incorporated by reference as specified in § 250.198). Subsurface-controlled SSSVs are not allowed on subsea wells.	*****	*The Joint Trades recommend the following change to the regulatory language:* *Recommended change:* *All SSSVs and their actuators installed after November 7, 2016 must meet all of the specifications and recommended practices of*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			ANSI/API Spec. 14A and ANSI/API RP 14B, including all annexes (both incorporated by reference as specified in § 250.198). Subsurface-controlled SSSVs are not allowed on subsea wells.
		Requirements derived from the documents incorporated in this section for SSVs, BSDVs, USVs, USVs, GLSDVs, and their actuators, include, but are not limited to, the following:	*It appears that there is a typographical error in 250.802(c). The term "USVs" is included twice in the proposed language and the term "SSSVs" is omitted. Also, as explained in the comment at 250.801, GLSDVs should not be considered SPPE.* *In addition, the proposed language uses the phrase "include, but are not limited to," which means that (c)(1)-(c)(7) are surplusage and that the operator must comply with every single "requirement" in the documents incorporated by reference.* *Recommend that the paragraph should read:* *"SSVs, BSDVs, SSSVs ~~USVs~~, USVs, ~~GLSDVs~~, and their actuators, must meet the following requirements derived from the documents incorporated in this section:"*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	(1) Each device must be designed to function and to close in 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.	DELETED	*The Joint Trades support the proposed change.*
	(2) All materials and parts must meet the original equipment manufacturer specifications and acceptance criteria.	All materials and parts must meet the original equipment manufacturer specifications and acceptance criteria.	*The Joint Trades recommend combining 250.802(c)(1) with 250.802(c)(6) because the two requirements appear duplicative. It is also recommended to consider changing the language to read as follows:* *You must use only parts and materials that meet original equipment manufacturers specifications; and you must use qualified personnel to repair or redress equipment.*
	(3) The device must pass applicable validation tests and functional tests performed by an API-licensed test agency.	The device must pass applicable validation tests and functional tests performed by an API-licensed test agency.	*Similar to the comment regarding 250.802(c)(1), the requirement in 250.802(c)(2) is contained in 250.802(c)(6), therefore we recommend deleting this paragraph. In addition, the paragraph is redundant in that applicable validation tests and functional tests are addressed in the standards incorporated by reference in 250.198.*
	(4) You must have requalification testing performed following manufacture design changes.	You must have requalification testing performed following manufacture design changes.	*The Joint Trades agree with the concept however recommend deleting this requirement because it is a manufacturer responsibility to meet the design*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			requirements of API standards, not the operator and the rule incorporates API Spec. Q1 by reference.
	(5) You must comply with and document all manufacturing, traceability, quality control, and inspection requirements.	You must comply with and document all manufacturing, traceability, quality control, and inspection requirements.	*The Joint Trades recommend deleting this requirement because it is the responsibility of the manufacturer to meet certification requirements of API Spec. Q1.*
	(6) You must follow specified installation, testing, and repair protocols.	You must follow specified installation, testing, and repair protocols.	*The Joint Trades recommend revising the language in 250.802(c)(5) for clarity as follows:* *"You must follow specified installation, testing, and repair procedures."*
	(7) You must use only qualified parts, procedures, and personnel to repair or redress equipment.	You must use only qualified parts, procedures, and personnel to repair or redress equipment.	*See comment under 250.802(c)(1).*
	(d) You must install and use SPPE according to the following table.	You must install and use SPPE according to the following table.	
	If… Then… Table		
	(1) If You need to install any SPPE… Then You must install certified SPPE.	If You need to install any SPPE… Then You must install SPPE that conforms to § 250.801	
	(2) If A non-certified SPPE is already in service… Then It may remain in service on that well.	If A non-certified SPPE is already in service… Then It may remain in service ~~on that well.~~	
	(3) If A non-certified SPPE requires offsite repair, remanufacturing, or any hot work such as welding… Then You must replace it with certified SPPE.	If A non-certified SPPE requires offsite repair, remanufacturing, or any hot work such as welding… Then You must replace it with SPPE that conforms to § 250.801.	*The following revision to 250.802(d)(3) is recommended.* *If you have an existing non-certified BSDV inventory as of November 7, 2016, you may use it to replace a non-certified valve. Other than this inventory, if a non-certified SPPE requires offsite repair, remanufacturing, or any hot work such as welding… Then You must replace it with SPPE that conforms to § 250.801.*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
§ 250.803 What SPPE failure reporting procedures must I follow?	(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 notice of equipment failure to the Chief, Office of Offshore Regulatory Programs or to the Chief's designee and 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 or purpose.	You must follow the failure reporting requirements contained in section 10.20.7.4 of ANSI/API Spec. 6A SSVs, BSDVs, GLSDVs and USVs and section 7.10 of ANSI/API Spec. 14A and Annex F of API RP 14B for SSSVs (all incorporated by reference in § 250.198). Within 30 days after the discovery and identification of the failure, you must provide a written notice of equipment failure to the manufacturer of such equipment and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. A failure is any condition that prevents the equipment from meeting the functional specification or purpose.	The SPPE failure definition as proposed in 30 CFR 250.803 (a) in its broadest interpretation includes maintenance issues and, thereby, the reporting of maintenance and routine repair items creates an administrative burden on operators and the agency with no improvement to safety and protection of the environment. *When looking at the complete list of SPPE, BSEE must recognize that this equipment has certain "wear" parts that, over time under normal conditions, will wear to the point of needing replacement. When these parts do wear, some operators may then consider the SPPE device to "fail to meet the functional specification." Other operators disagree with this view and consider the wear part to be inclusive in the functional specification(s), meaning the SPPE is designed to wear. Further, it is important to highlight that most, if not all, of these wear parts can be and are replaced without removing the SPPE from service. Additionally, given the published requirements for replacing non-certified SPPE, we suggest aligning the failure reporting threshold with this same guidance. In addition, it is important to note that the preamble to the September 2016 Production Safety Systems final rule (Federal Register, Volume 81, Number 173) stated,*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			*The final rule defines a failure as, "any condition that prevents the equipment from meeting the functional specification" This is intended to ensure that **design defects** are identified and corrected and that equipment is replaced before it fails [emphasis added].* *If the intention is to identify design defects that create safety and environmental risks, then clearly maintenance and/or wear issues should not be considered failures. Therefore, the definition of failure must be clarified.* *The Joint Trades suggest revising the definition of SPPE failure to align with appropriate industry standards. For SSVs, USVs, BSDVs we are recommending API Spec 6A and API Std 6AV2. For SSSVs we are recommending API Spec 14A and API RP 14B. We are differentiating between surface and subsurface SPPE to align with the industry standards. In addition, we strongly recommend that BSEE and industry convene a workshop(s) to determine the best repository/clearinghouse for collecting failure data. Until a mutually-agreeable solution can be developed, we are recommending that failure reports be documented and maintained as described in the applicable API standards, and the failure reports be provided to BSEE on request.* *Recommended regulatory changes to 250.803(a)*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			are as follows: *For SSVs, USVs, and BSDVs that require remanufacture or offsite repair as defined in API Spec 6A and API Std 6AV2, you must follow the failure reporting requirements outlined in Section 8 of API Std 6AV2. Your initial failure notification report and subsequent failure analysis reports either from you or from the manufacturer as stipulated in Section 10.20.7.4 of API Spec 6A, must be made available to BSEE upon request.* *For SSSVs that require repair as defined in API Spec 14A and API RP 14B, you must follow the failure reporting requirements outlined in Section 8.4.2 and Annex B of API RP 14B. Your initial failure notification report and the subsequent failure analysis reports either from you or from the manufacturer as stipulated in Section 6.6 of API 14A, must be made available to BSEE upon request.*
	(b) You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that manufacturer and the Chief, Office of Offshore Regulatory Programs or the Chief's designee receives a copy of the analysis report. You must also ensure that the results of the investigation and any corrective action are documented in the analysis report.	You must ensure that an investigation and a failure analysis are performed within 120 days of the failure to determine the cause of the failure. If the investigation and analyses are performed by an entity other than the manufacturer, you must ensure that the analysis report is submitted to the manufacturer and to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section. You must also ensure that the results of the	*Reporting forms and timing are addressed in the industry standards recommended in our comment at 250.803(a). Therefore, this 250.803(b) becomes redundant and duplicative. The Joint Trades recommend deleting this paragraph.*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
		investigation and any corrective action are documented in the analysis report.	
	(c) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs or the Chief's designee.	If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such changes, report the design change or modified procedures in writing to BSEE through the Chief, Office of Offshore Regulatory Programs, unless BSEE has designated a third party as provided in paragraph (d) of this section.	*Reporting responsibilities are addressed in the industry standards recommended in our comment at 250.803(a). Therefore, this 250.803(c) becomes redundant and duplicative. The Joint Trades recommend deleting this paragraph.*
	(d) Any notifications or reports submitted to the Chief, Office of Offshore Regulatory Programs under paragraphs (a), (b), and (c) of this section must be sent to: Bureau of Safety and Environmental Enforcement; VAE– ORP, 45600 Woodland Road, Sterling, VA 20166.	BSEE may designate a third party to receive this data on behalf of BSEE. If BSEE designates a third party, you must submit the information required in this section to the designated third party, as directed by BSEE.	*As discussed in the comments to 250.803(a), the Joint Trades recommend that BSEE and industry convene a workshop(s) to reach resolution on an appropriate repository for receiving and maintaining industry failure data. Therefore, until such time as a workshop(s) is held, we recommend deleting paragraph (d).*
§ 250.814 Design, installation, and operation of SSSVs-dry trees	You must design, install, and operate (including repair, maintain, and test) an SSSV to ensure its reliable operation.	*****	
	(d) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with API RP 14B (incorporated by reference as specified in § 250.198). For additional SSSV testing requirements, refer to § 250.880.	You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with ANSI/API RP 14B (incorporated by reference as specified in § 250.198). For additional SSSV testing requirements, refer to § 250.880.	*The Joint Trades recommend that this paragraph be deleted because it is duplicative with 250.802(b).*
§ 250.821 Emergency action and safety system shutdown-dry trees	(a) In the event of an emergency, such as an impending National Weather Service-named tropical storm or hurricane:	If your facility is impacted or will potentially be impacted by an emergency situation (*e.g.*, an impending National Weather Service-named tropical	*BSEE indicated in the request for additional information that the intent of this regulation was to require operators to complete the outlined activities prior to the evacuation of the facility. If*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
		storm or hurricane, ice events in the Arctic, or post-earthquake), you must:	*this is BSEE's intent, then the regulation should state that specific purpose. Suggest revising 250. 821 to read:* *"If your facility is impacted or will potentially be impacted by an emergency situation (e.g., an impending National Weather Service-named tropical storm or hurricane, ice events in the Arctic, or post-earthquake), you must complete the following activities prior to evacuation of the facility:"*
§ 250.828 Design, installation, and operation of SSSVs-subsea trees	You must design, install, and operate (including repair, maintain, and test) an SSSV to ensure its reliable operation.	*****	
	(c) You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with your Deepwater Operations Plan (DWOP) and API RP 14B (incorporated by reference as specified in § 250.198). For additional SSSV testing requirements, refer to § 250.880.	You must design, install, maintain, inspect, repair, and test all SSSVs in accordance with your Deepwater Operations Plan (DWOP) and ANSI/API RP 14B (incorporated by reference as specified in § 250.198). For additional SSSV testing requirements, refer to § 250.880.	*The Joint Trades recommend that this paragraph be deleted because it is duplicative with 250.802(b).*
§ 250.835 Specification for all boarding shutdown valves (BSDVs) ~~and gas lift shutdown valves (GLSDV)~~ associated with subsea systems.	You must install a BSDV on the pipeline boarding riser. All new BSDVs and any BSDVs removed from service for remanufacturing or repair and their actuators installed on the OCS must meet the requirements specified in §§250.801 through 250.803. In addition, you must: (a) Ensure that the internal design pressure(s) of the pipeline(s), riser(s), and BSDV(s) is fully rated for the	*****	*For deepwater large diameter lines, location of the BSDV within 10' from the edge of platform is generally not feasible.* *Recommendation: (c) Locate the BSDV within 10 feet) (or fitting makeup plus 10 feet, or according to your approved DWOP) of the first point of access to the boarding pipeline riser (i.e., within 10 feet of the point of entry on the platform if the BSDV is*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	maximum pressure of any input source and complies with the design requirements set forth in subpart J, unless BSEE approves an alternate design. (b) Use a BSDV that is fire rated for 30 minutes, and is pressure rated for the maximum allowable operating pressure (MAOP) approved in your pipeline application. (c) Locate the BSDV within 10 feet of the first point of access to the boarding pipeline riser (*i.e.*, within 10 feet of the edge of platform if the BSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the BSDV is vertical). (d) Install a temperature safety element (TSE) and locate it within 5 feet of each BSDV.		*horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the BSDV is vertical);*
§ 250.837 Emergency action and safety system shutdown-subsea trees	(a) 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.	If your facility is impacted or will potentially be impacted by an emergency situation (*e.g.*, an impending National Weather Service-named tropical storm or hurricane, ice events in the Arctic, or post-earthquake), you must shut-in all subsea wells unless otherwise approved by the District Manager. A shut-in is defined as a closed BSDV, USV, ~~GLSDV~~, and surface-controlled SSSV.	*The Joint Trades recommend adding boundary condition like in 250.821. Examples of modified language may include:* *Shut-in just prior to evacuation, OR* *If full remote real-time monitoring AND control capabilities exist, shut-in prior to exceeding safe environmental operating conditions as stipulated by regulatory approvals.*
	(b) When operating a mobile offshore drilling unit (MODU) or other type of workover vessel in an area with producing subsea wells, you must:	When operating a vessel (*e.g.*, mobile offshore drilling unit (MODU) or other type of workover or intervention	*The Joint Trades do not recommend adoption of the proposed rule language in 250.837(b). By adding the generic term "vessel" followed by*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
		vessel) in an area with subsea infrastructure, you must:	*"mobile offshore drilling unit (MODU) or other type of workover or intervention vessel" as examples, the requirement is made more ambiguous. The proposed language may create interpretations that the presence of any "vessel" such as an offshore support vessel or standby vessel would trigger this requirement even if the vessel is not engaged in well operations. Intervention vessels that do not latch onto the well mitigate dropped object concerns through use of safe overboarding zones. It is overly burdensome to apply these requirements to ROV vessels that do not latch onto the well for wellbore intervention activities. OOC recommends adopting language similar to the current rule, such as:* *"When operating a mobile offshore drilling unit (MODU) or other type of workover or intervention vessel in an area with producing subsea wells, you must:"*
	(2) Establish direct, real-time communications between the MODU or other type of workover vessel and the production facility control room and prepare a plan to be submitted to the appropriate District Manager for approval, as part of an Application for Permit to Drill (BSEE–0123) or an Application for Permit to Modify (BSEE–0124), to shut-in any wells that could be affected by a dropped object. If an object is dropped, the driller (or other authorized rig floor personnel) must immediately secure the well directly under the MODU or other type of workover vessel	Establish direct, real-time communications between the vessel and the production facility control room and develop a dropped objects plan, as required in § 250.714. If an object is dropped, you must immediately secure the well directly under the vessel while simultaneously communicating with the platform to shut-in all affected wells. You must also maintain without disruption, and continuously verify, communication between the production facility and the vessel. If communication is lost between the vessel and the platform for 20 minutes or more, you must	*The Joint Trades support the proposed changes in 250.837(b)(2). We recommend a minor clarification as follows:* *Establish direct, real-time communications between the vessel and the production facility control room and develop a dropped objects plan, as required in § 250.714. If an object is dropped, you must immediately secure the well directly under the ~~vessel~~ mobile offshore drilling unit (MODU) or other type of workover or intervention*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	using the ESD station near the driller's console while simultaneously communicating with the platform to shut-in all affected wells. You must also maintain without disruption, and continuously verify, communication between the platform and the MODU or other type of workover vessel. If communication is lost between the MODU or other type of workover vessel and the platform for 20 minutes or more, you must shut-in all wells that could be affected by a dropped object.	shut-in all wells that could be affected by a dropped object.	*vessel while simultaneously communicating with the platform to shut-in all affected wells. You must also maintain without disruption, and continuously verify, communication between the production facility and the vessel. If communication is lost between the vessel and the platform for 20 or more continuous minutes ~~minutes or more~~, you must shut-in all wells that could be affected by a dropped object. This requirement does not apply to vessels located in a designated safe zone.*
	(2) Pipeline pressure safety high and low (PSHL) sensor. In the event that either a high or a low pressure condition is detected by a PSHL sensor located upstream of the BSDV, you must secure the affected well and pipeline, and all wells and pipelines associated with a dual or multi pipeline system, by closing the BSDVs, USVs, and surface controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must obtain approval from the appropriate District Manager to resume production in the unaffected pipeline(s) of a dual or multi pipeline system. If the PSHL sensor activation was a false alarm, you may return the wells to production without contacting the appropriate District Manager.	*****	*To clarify when contacting the appropriate District Manager is necessary when returning wells to production, we recommend the following change to 250.837(c)(2):* *(2) Pipeline pressure safety high and low (PSHL) sensor. In the event that either a high or a low pressure condition is detected by a PSHL sensor located upstream of the BSDV, you must secure the affected well and pipeline, and all wells and pipelines associated with a dual or multi pipeline system, by closing the BSDVs, USVs, and surface controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must obtain approval from the appropriate District Manager to resume production in the unaffected pipeline(s) of a dual or multi pipeline system. ~~If the PSHL sensor activation was a false alarm, you may return the wells to production without contacting the appropriate District Manager.~~ If the PSHL sensor activation was not accompanied by an increase in*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			pressure above the MAOP, or the loss of integrity of the pipeline, you may return the wells to production without contacting the appropriate District Manager.
	(5) Subsea ESD (MODU). In the event of an ESD activation that is initiated by a dropped object from a MODU or other type of workover vessel, you must secure all wells in the proximity of the MODU or other type of workover vessel by closing the USVs and surface controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must notify the appropriate District Manager before resuming production.	*Subsea ESD (vessel).* In the event of an ESD activation that is initiated by a dropped object from a vessel, you must secure all wells in the proximity of the vessel by closing the USVs and surface-controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must notify the appropriate District Manager before resuming production.	*OOC does not recommend adoption of the proposed rule language in 250.837(e)(5). Like the comment on 250.837(b), by adding the generic term "vessel," the requirement is made more ambiguous. The proposed language may create interpretations that the presence of any "vessel" such as an offshore support vessel or standby vessel would trigger this requirement even if the vessel is not engaged in well operations. OOC recommends adopting language similar to the current rule, such as:* *"Subsea ESD (MODU). In the event of an ESD activation that is initiated by a dropped object from a MODU or other type of workover or intervention vessel, you must secure all wells in the proximity of the MODU or other type of workover or intervention vessel by closing the USVs and surface controlled SSSVs in accordance with the applicable tables in §§ 250.838 and 250.839. You must notify the appropriate District Manager before resuming production."*

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§ 250.841 Platforms		NEW PARAGRAPH (c) If you plan to make a major modification to any facility you must follow the requirements in § 250.900(b)(2). A major modification is defined in § 250.900(b)(2).	*The language in 250.841(c) should be clarified. As proposed, the language can lead an operator to think "major facility modification: is a defined term in the regulation. The term "major modification" as defined in 30 CFR 250 applies only to a platform structure. Therefore, the Joint Trades are proposing the following revised language:* *(c) If you plan to make a ~~major~~ modification to any production safety system that also involves a major modification to the platform structure, you must follow the requirements in § 250.900(b)(2). A major modification to a platform structure is defined in § 250.900(b)(2).*

<table>
<tr><th>Reference</th><th colspan="2">Current Rule Language</th><th colspan="2">December 2017 Proposed Rule</th><th>Joint Trades Comments</th></tr>
<tr><td>§ 250.842 Approval of safety systems design and installation features</td><td colspan="2">(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:</td><td colspan="2">Before you install or modify a production safety system, you must submit a production safety system application to the District Manager. The District Manager must approve your production safety system application before you commence production through or utilize the new or modified system. The application must include the information prescribed in the following table:</td><td>For clarification purposes, the Joint Trades recommend changing the first sentence of the paragraph to read “You must submit a production safety system application to the District Manager to install or modify a production safety system.”

In addition, the terms “information”, “diagrams” and “designs” are used inconsistently as collective terms for “diagram”, “chart”, “schematic”, “plan”, “schedule”, etc. This appears to be a carryover from previous iterations of Subpart H and the OCS orders before that. Imprecise and/or inconsistent language is undesirable in a regulation. We propose the term “design documentation” or “design documents” as the collective term.

Recommended language:
<s>Before you install or modify a production safety system, you must submit a production safety system application to the District Manager.</s> You must submit a production safety system application to the District Manager to install or modify a production safety system. The District Manager must approve your production safety system application before you commence production through or utilize the new or modified system. The application must include the design documentation prescribed in the following table:</td></tr>
<tr><td></td><td>You must submit:</td><td>Details and/or additional requirements</td><td>You must submit:</td><td>Details and/or additional requirements</td><td></td></tr>
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	(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	(1) Safety analysis flow diagram (API RP 14C, Annex B) and Safety Analysis Function Evaluation (SAFE) chart (API RP 14C, section 6.3.3) (incorporated by reference in 250.198).	Your safety analysis flow diagram must show the following: (i) Well shut-in tubing pressure; (ii) Piping specification breaks, piping sizes; (iii) Pressure relieving device 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-	*The Joint Trades recommend the following changes to 250.842(a)(1):* *(ii) should be grouped with bullet (vii) because of the overlap in content. (ii) should be removed. See comments to (vii) below.* *Recommended change:* *~~(ii) Piping specification breaks, piping sizes;~~* *In (iv), metering devices should be removed. Metering devices are considered instrumentation and size, capacity and working pressures of metering devices are typically not included on SAFE charts.* *Recommended language:* *(iv) Size, capacity, and design working pressures of separators, flare scrubbers, heat exchangers, and treaters, storage tanks, and compressors ~~and metering devices~~;* *In (vii), the word "piping" should be included at the beginning of this bullet as it was unclear that this bullet applied to piping except that the code reference, API RP 14E, is a piping design standard. Adding the word makes it more explicit.* *Recommended language:* *(vii) Piping sizes and maximum allowable working pressures as determined in accordance with API*

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		flammable liquid as described in API RP 500 and 505 (both incorporated by reference as specified in § 250.198). (vii) Size and maximum allowable working pressures as determined in accordance with API RP 14E, (incorporated by reference as specified in § 250.198).		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 API RP 505 (both incorporated by reference as specified in § 250.198); and (vii) Size and maximum allowable working pressures as determined in accordance with API RP 14E (incorporated by reference as specified in § 250.198).	*RP 14E (incorporated by reference as specified in § 250.198) including the locations of piping specification breaks.* *The Joint Trades also recommend that chemical injection systems that have less than 770 gallon storage capacity be exempt from 250.842(a)(1)(vi) based upon the following:* • *On the majority of the Gulf of Mexico shelf facilities, the storage capacity of the injection system is often less than 260 gallons. For the majority of the chemicals used, the flammability of the products is lessened extensively due to dilution with water and blending of the chemical; thereby, the actual flammability of the total product is reduced. Only a small amount of solvent additive (active ingredients) is what classifies these chemicals to have a flash point below 100 degrees F.* • *These low volume chemical systems do not present the same hazards as atmospheric hydrocarbon process vessels. Process vessels have the potential for constant in and out flow of hydrocarbons under pressure. Chemicals in storage are never under pressure, and the fluid is static. Any potential flash or vapors are very minimal by the time the chemical is on the facility and placed in service.*

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					• *These low volume chemical systems are already analyzed and protected on the facility in accordance with API RP 14C. Adding these systems to the facility drawings will not enhance safety or reduce risk.* *Recommended regulatory language:* *(iv)size, capacity, and design working pressures of hydrocarbon-handling vessels, and chemical injection systems with an individual storage capacity greater than 770 gallons 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).*
	(2) A safety analysis flow diagram (API RP 14C, Appendix E) and the related Safety Analysis Function Evaluation (SAFE) chart (API RP 14C, subsection 4.3.3) (incorporated by reference as specified in § 250.198).	If processing components are used, other than those for which Safety Analysis Checklists are included in API RP 14C, you must use the same analysis technique and documentation to determine the effects and requirements of these components upon the safety system.	(2) Electrical one-line diagram	Showing elements, including generators, circuit breakers, transformers, bus bars, conductors, battery banks, automatic transfer switches, uninterruptable power supply (UPS), dynamic (motor) loads, and static (*e.g.*, electrostatic treater grid, lighting panels, etc.) loads. You must	*The Joint Trades recommend the term "battery banks," be removed from the list of items to include in electrical one lines. Battery banks would exist on a DC system, while everything else is 120VAC and higher. Supporting this is BSEE's decision to remove "including the safety shutdown system" from the definition that was previously found in 250.842(a)(3)(iii). Thus, the details would read:* *Showing elements, including generators, circuit breakers, transformers, bus bars, conductors, ~~battery banks,~~ automatic transfer switches, uninterruptable power supply (UPS), dynamic (motor) loads, and static (e.g., electrostatic treater*

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		also include a functional legend.	*grid, lighting panels, etc.) loads. You must also include a functional legend.* *The Joint Trades also recommend that language be added to exempt existing OCS facilities until a major modification is made to the electrical system as follows:* *(2) Electrical one-line diagram. Existing facilities installed prior to the effective date of this rule are exempt from this requirement until a major modification is made to the electrical system.* *The recommended addition is based upon the following:* • *Many of the Gulf of Mexico operators have acquired facilities from other companies, and many of these facilities have changed ownership several times over the years. The original documents such as electrical one-line drawings are unavailable or have not been updated after the initial installation and submittal. Over the years, BSEE has not requested these documents when facility modifications were submitted for approval; therefore, they have not been generated or produced.* • *To update or create new drawings to this level of detail along with engineering certifications will very expensive and in some cases, will*

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					result in facilities becoming uneconomical. For existing facilities, the electrical one-line drawings should only be required when major modifications are made to the facility's electrical system.
	(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 or API RP 505 (both incorporated by reference as specified in § 250.198)	(3) Area classification diagram	A plan for each platform deck and outlining all classified areas. You must classify areas according to API RP 500 or API RP 505 (both incorporated by reference as specified in § 250.198). The plan must contain: (i) All major production equipment, wells, and other significant hydrocarbon and class 1 flammable sources, and a description of the type of decking, ceiling, walls (*e.g.*, grating or solid), and firewalls; and	*Identification of control rooms and MCC rooms is not included in API RP 500 and API RP 505. Therefore, we recommend modifying 250.842(a)(3)(i) as follows:* *All major production equipment, wells, and other significant hydrocarbon and class 1 flammable sources, and a description of the type of decking, ceiling, walls (e.g., grating or solid), and firewalls; and* *The location of generators, ~~control rooms, motor control center (MCC) buildings~~, and any other building or major structure on the platform.*

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				The location of generators, control rooms, motor control center (MCC) buildings, and any other building or major structure on the platform.	
		(ii) Identification of all areas where potential ignition sources, including non-electrical ignition sources, are to be installed showing:		DELETED	*The Joint Trades support deleting this paragraph.*
		(A) All major production equipment, wells, and other significant hydrocarbon sources, and a description of the type of decking, ceiling, and walls (*e.g.*, grating or solid) and firewalls and;		DELETED	*The Joint Trades support deleting this paragraph.*
		(B) the location of generators, control rooms, panel boards, major cabling/conduit routes, and identification of the primary wiring method		DELETED	*The Joint Trades support deleting this paragraph.*

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		(*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.		DELETED	*The Joint Trades support deleting this paragraph.*
	(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.	(4) A schematic piping and instrumentation diagram, for new facilities.	A detailed diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.	*The Joint Trades recommend the following modification to provide better clarity:* *(4) A ~~schematic~~ piping and instrumentation diagram, for new facilities.* *A detailed flow diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.*
	(b) In the production safety system application, you must also certify the following:		You must develop and maintain the following diagrams and make them available to BSEE upon request:		*The Joint Trades recommend the following change to more precise language:* *You must develop and maintain the following ~~diagrams~~ design documents and make them available to BSEE upon request:*

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		Diagram:	**Details and/or additional requirements:**	*The Joint Trades recommend the following change to more precise language:* ~~**Diagram:**~~ ***Design Document*:**
	(1) That all electrical installations were designed according to API RP 14F or API RP 14FZ, as applicable (incorporated by reference as specified in § 250.198);			
	(2) That the designs for the mechanical and electrical systems under paragraph (a) of this section were reviewed, approved, and stamped by an appropriate registered professional engineer(s). The registered professional engineer must be registered in a State or Territory of the United States and have sufficient expertise and experience to perform the duties; and	(1) Additional electrical system information,	(i) Cable tray/conduit routing plan which identifies the primary wiring method (*e.g.*, type cable, conduit, wire); (ii) Cable schedule; and (iii) Panel board/junction box location plan.	*The Joint Trades offer that paragraph (i) is unduly burdensome to operators of older facilities wherein the drawings were either never created or served only initial fabrication purposes. In addition, we question the need for the cable schedule required by (ii) because it seems to be too detailed since the cable tray/conduit routing plan should provide the relevant information.* *Regarding item (iii), these items should be added to the requirements for an area classification drawing in 250.842(a)(3) to prevent the requirement to carry multiple drawing sets.* *Therefore, we recommend the following regulatory language:* *(i) For new facilities, cable tray/conduit routing plan which identifies the primary wiring method (e.g., type cable, conduit, wire);* *~~(ii) Cable schedule;~~ and* *(iii) Panel board/junction box location plan if this information is not shown on the area*

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				classification drawing required in 250.843(a)(3)
	(3) That a hazards analysis was performed in accordance with § 250.1911 and 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 facility.	(2) 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.	*The Joint Trades recommend the following language change because the phrase "and the method and frequency of calibration" appears to be redundant. In addition, methods and frequency of calibration for these devices are specified in API RP 14C and 250.880(3).* *Recommended language:* *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; and the method used for detection. ~~and the method and frequency of calibration.~~*
		(3) Revised P&ID for existing facilities	A detailed diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.	*The Joint Trades recommend the following change to more precise language:* *(3) Revised Piping and instrumentation diagram ~~P&ID~~ for existing facilities* *A detailed flow diagram which shows the piping and vessels in the process flow, together with the instrumentation and control devices.*
	(c) Before you begin production, you must certify, in a letter to the District Manager, that the mechanical	In the production safety system application, you must also certify the following:		

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	and electrical systems were installed in accordance with the approved designs.		
		(1) That all electrical installations were designed according to API RP 14F or API RP 14FZ, as applicable (incorporated by reference as specified in § 250.198);	*The Joint Trades recommend the following change to more precise language:* *That all electrical ~~installations~~ systems were designed and installed according to API RP 14F or API RP 14FZ, as applicable (incorporated by reference as specified in § 250.198);*
		(2) That the designs for the mechanical and electrical systems that you are required to submit under paragraph (a) of this section were reviewed, approved, and stamped by an appropriate registered professional engineer(s). For modified systems, only the modifications are required to be approved and stamped by an appropriate registered professional engineer(s). The registered professional engineer must be registered in a State or Territory of the United States and have sufficient expertise and experience to perform the duties; and	*The Joint Trades recommend the following revisions to align with terminology utilized by engineering licensing boards. It is important to use the term "seal" as it has specific legal meaning as opposed to loosely throwing around the terms "reviewed", "approved" and "stamped", especially when it comes to as-built documents. Also, the term "licensed" is preferred over "registered."* *Recommended language:* *That the ~~designs~~ design documents for the mechanical and electrical systems that you are required to submit under paragraph (a) of this section ~~were reviewed, approved, and stamped by an appropriate registered~~ are sealed by a licensed professional engineer(s). For modified systems, only the permanent modifications are required to be ~~approved and stamped by an appropriate registered~~ sealed by a licensed professional engineer(s). The ~~registered~~ professional engineer must be ~~registered~~ licensed in a State or Territory*

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			of the United States and have sufficient expertise and experience to perform the duties; and
	(d) Within 60 days after production commences, you must certify, in a letter to the District Manager, that the as-built diagrams for the new or modified production safety systems outlined in paragraphs (a)(1) and (2) of this section and the piping and instrumentation diagrams are on file and have been certified correct and stamped by an appropriate 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.	Within 60 days after production commences, you must submit to the District Manager the as-built diagrams for the new or modified production safety systems outlined in paragraphs (a)(1), (2), and (3) of this section, the diagrams must be reviewed, approved, and stamped by an appropriate 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.	*Sealing of as-built design documents places a significant undue burden on industry by requiring the PE to be present at all times during all phases of construction over extended periods of time, and multiple locations. The intent of as-built design documents is to ensure that the final design documents accurately reflect what was installed on the location. Industry understands the importance of having accurate drawings and BSEE's desire to ensure that facility drawings are the most recent version, therefore we offer the following feasible solution:* *(d) Within ~~60~~ 90 days after placing new or modified production safety systems in service, you must submit to the District Manager the as-built design documents outlined in paragraphs (a)(1), (2), and (3) of this section. ~~The as-built design documents must be reviewed for compliance with applicable design regulations and sealed accordingly by a licensed 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.~~ You must certify in an accompanying letter that the as-built design documents have been reviewed for compliance with applicable regulations and accurately represent the new or modified system as installed.*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	(e) All as-built diagrams outlined in paragraphs (a)(1) and (2) of this section must be submitted to the District Manager within 60 days after production commences.	DELETED	*The Joint Trades support deletion of this paragraph.*
	(f) You must maintain information concerning the approved designs 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.	(e) You must maintain information concerning the approved designs 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.	*The Joint Trades recommend the following changes to improve clarity:* *(e) You must maintain the approved design documents as well as the piping and instrumentation diagrams 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.*
§ 250.851 Pressure vessels (including heat exchangers) and fired vessels	(a) Pressure vessels (including heat exchangers) and fired vessels supporting production operations must meet the requirements in the following table:	*****	
	(1) Pressure and fired vessels	*****	*The Joint Trades recommend the following regulatory language to clarify that it was not intended for small hydraulic accumulators and pulsation dampeners to be included in this section.* *1) Pressure and fired vessel, except small hydraulic accumulator and pulsation dampeners designed to alternative codes/standards.*

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	(2) Existing uncoded pressure and fired vessels (i) in use on November 7, 2016; (ii) with an operating pressure greater than 15 psig; and (iii) that are not code stamped in accordance with the ANSI/ASME Boiler and Pressure Vessel Code.	Existing uncoded pressure and fired vessels; (i) with an operating pressure greater than 15 psig; and (ii) that are not code stamped in accordance with the ANSI/ASME Boiler and Pressure Vessel Code	*Similar to the comment at 250.851(1), the Joint Trades recommend the following change:* *Existing uncoded pressure and fired vessels, except small hydraulic accumulator and pulsation dampeners designed to alternative codes/standards; (i) with an operating pressure greater than 15 psig; and (ii) that are not code stamped in accordance with the ANSI/ASME Boiler and Pressure Vessel Code*
	Must be justified and approval obtained from the District Manager for their continued use after March 1, 2018.	Must be justified and approval obtained from the District Manager for their continued use.	*Deleting the March 1, 2018 deadline would imply that this requirement will take effect immediately upon publication of the 30 CFR part 250, subpart H. The Joint Trades recommend a new compliance date of January 1, 2019 be added to ensure that adequate time is allocated for implementation.*
	(3) Pressure relief valves	*****	*For chemical injection and hydraulic systems, a small ASME Coded relief valve is either not available, far too large for the service, or the reseat pressure would render a hydraulic service inoperable until pressure is rebuilt.* *Therefore, the Joint Trades recommend the following change:* *Pressure relief valves, except for fractional inch chemical relief valves and hydraulic relief valves, provided these are tested or replaced on a yearly basis.*
§ 250.853 Safety Sensors	You must ensure that:		

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		NEW PARAGRAPH (d) All level sensors are equipped to permit testing through an external bridle on all new vessel installations where possible, depending on the type of vessel for which the level sensor is used.	*The phrase "where possible" is ambiguous and open to a wide range of interpretations. Therefore, the Joint Trades recommend the following change to clarify the intent of paragraph (d):* *All level sensors are equipped to permit testing through an external bridle on all new vessel installations ~~where possible~~ except where other level sensors are approved in your production safety systems application, depending on the type of vessel for which the level sensor is used.*
§ 250.865 Surface pumps	You must equip pump installations with the protective equipment required in API RP 14C, Appendix A—A.7, Pumps (incorporated by reference as specified in § 250.198).	*****	*If the 8th Edition of API RP 14C is incorporated by reference as proposed in 250.198, then the reference to API RP 14C in 250.865(a) will need to be changed to read as follows:* *You must equip pump installations with the protective equipment required in API RP 14C, Appendix A—~~A.7~~ A.8, Pumps (incorporated by reference as specified in § 250.198).*
	(d) The PSL must be placed into service when the pump discharge pressure has risen above the PSL sensing point, or within 45 seconds of the pump coming into service, whichever is sooner.	*****	*If the proposed changes in 250.870 are adopted in the final rule, we recommend that 250.865(d) be changed to reference 250.870 for consistency of implementation. The following change is recommended:* *(d) ~~The PSL must be placed into service when the pump discharge pressure has risen above the PSL sensing point, or within 45 seconds of the pump~~*

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			~~coming into service, whichever is sooner.~~ The PSL bypass must meet the requirements of 250.870.
§ 250.867 Temporary quarters and temporary equipment	(a) The District Manager must approve all temporary quarters to be installed in production processing areas or other classified areas on OCS facilities. You must equip such temporary quarters with all safety devices required by API RP 14C, Appendix C (incorporated by reference as specified in § 250.198).	You must equip temporary quarters with all safety devices required by API RP 14C, Annex G (incorporated by reference as specified in § 250.198). The District Manager must approve the safety system/safety devices associated with the temporary quarters prior to installation.	*Requiring District Manager approval before installation of temporary quarters is inconsistent with other similar requirements contained in Subpart H. For example, 250.842 requires submission for approval of drawings for installation or modification of production safety systems followed by submission of as-built drawings 60 days after production commences. Installation of these critical safety systems are not contingent upon District Manager approval to begin installation; however, production cannot commence until District Manager approval is received. OOC recommends that a similar approach be adopted for temporary quarters. The following language is suggested:* *"You must equip temporary quarters with all safety devices required by API RP 14C, Annex G (incorporated by reference as specified in § 250.198). You must submit plans for the safety systems/safety devices to the District Manager prior to installation of the temporary quarters. The District Manager must approve the safety system/safety devices associated with the temporary quarters prior to occupation of the temporary quarters."*
	(c) Temporary equipment associated with the production process system, including equipment	*****	*It is not feasible to submit certain small temporary equipment meant for testing and maintenance to the District Manager prior to installation.*

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	used for well testing and/or well clean-up, must be approved by the District Manager.		*Therefore, the Joint Trades recommend the following:* *Major temporary equipment associated with the production process system, including equipment used for well testing and/or well clean-up, must be approved by the District Manager.*
		NEW PARAGRAPH (d) The District Manager must approve temporary generators that would require a change to the electrical one-line diagram in § 250.842(a).	*The Joint Trades recommend 250.867(d) be deleted. Generators are a vital piece of equipment that not only provide power for living conditions, but more importantly provides power for SCADA systems, gas detection systems, fire detection systems, process systems, and safety/pollution control devices. Requiring an operator to seek BSEE approval prior to the installation of such a vital piece of equipment not only creates less than desirable living conditions but loss of control of operations as well. An operator's SEMS program provides guidance and procedures for the installation of temporary or permanent equipment. In addition, temporary generators are a minimal impact to the overall safety system. These generators are put in pre-designated electrical switchgear systems for auxiliary power while the primary generator is inoperable and sent in for repair. This spare switchgear breaker should already be identified on one-line electrical drawings.*
§ 250.870 Time delays on pressure safety low (PSL) sensors	(a) You may apply any or all of the industry standard Class B, Class C, or Class B/C logic to all applicable PSL sensors installed on process equipment, as long as	You may apply ~~any or all of the~~ industry standard Class B, Class C, or Class B/C logic to applicable PSL sensors installed on process equipment~~, as long as~~	*Clarification should be provided on how the proposed change to 250.870 will impact departure requests that were issued under the current (2016*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	the time delay does not exceed 45 seconds. Use of a PSL sensor with a time delay greater than 45 seconds requires BSEE approval in accordance with § 250.141. You must document on your field test records any use of a PSL sensor with a time delay greater than 45 seconds. For purposes of this section, PSL sensors are categorized as follows:	~~the time delay does not exceed 45 seconds~~. If the device may be bypassed for greater than 45 seconds, you must monitor the bypassed devices in accordance with § 250.869(a). You must document on your field test records any use of a PSL sensor with a time delay greater than 45 seconds. For purposes of this section, PSL sensors are categorized as follows:	*requirements) for PSL time delays that are greater than 45 seconds.*
	(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.	*****	*The examples given in 250.870(a)(1) are non-14C devices and on reciprocating compressors this timer is typically set for 90 seconds. Suggest deleting the "but not more than 45 seconds" since that is covered above in 250.870(a) or change the example to "a hydrocarbon pump PSL sensor which will typically clears in 15 seconds but before 45 seconds."*
	(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).	*****	*The Joint Trades recommend adding the following sentence to 250.870(a)(2) for clarification: Class C safety devices while bypassed should be monitored until they are in full service.* *Recommended paragraph would read as follows: (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). Class C safety devices while bypassed should be monitored until they are in full service.*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	(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 startup 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 and either:	*****	*For clarification, the Joint Trades recommend rewording 250.870(a)(3) as follows:* *(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. They are often used for compressor discharge PSL(s) for the loading process. These devices are also used to ensure that the PSL sensors are not unnecessarily bypassed during startup 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 and either:*
	(i) The Class B timer expires no later than 45 seconds from start activation, or	*****	*The Joint Trades recommend the removal of the phrase "no later than 45 seconds from start activation" as this is covered under 250.870(a) which allows going beyond 45 seconds provided the Class B timer is monitored and documented.* *Class B/C timers are used on Compressor discharge PSL(s). Turbine compressors typically take up to 3 minutes to clear the discharge PSL(s) after loading the compressor and reciprocating compressors can take more than 45 seconds. There are situations (Pigging Pumps, Equalization Pumps, Pipeline Pumps, etc.) where it takes longer than 45 seconds to build up line pressure and clear the PSL to normal operating pressure.*
	(b) If you do not install time delay circuitry that bypasses activation of PSL sensor shutdown logic for	*****	*250.870(b) should be deleted because it is a duplicative requirement. There are manual*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	a specified time period on process and product transport equipment during startup and idle operations, you must manually bypass (pin out or disengage) the PSL sensor, with a time delay not to exceed 45 seconds.		*bypassing rules covered under 250.869 that allow the bypass a safety device for unlimited time periods provided that the operator is monitoring the sensing device and able to shut it in.*
§ 250.872 Atmospheric vessels	(a) 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). Transport tanks approved by the U.S. Department of Transportation, that are sealed and not connected via interconnected piping to the production process train and that are used only for storage 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.	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.6 (incorporated by reference as specified in § 250.198). Transport tanks approved by the U.S. Department of Transportation, that are sealed and not connected via interconnected piping to the production process train and that are used only for storage 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. The atmospheric vessels connected to the process system that contains a Class I liquid and the associated pumps must be reflected on the corresponding drawings.	*If the 8th Edition of API RP 14C is incorporated into the final rule as proposed the reference to section A.5 in this paragraph should be changed to A.6. In addition, the Joint Trades recommend this paragraph be more specific when referencing "corresponding drawings."* *Recommended language is as follows:* *(a) 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.6 (incorporated by reference as specified in § 250.198). Transport tanks approved by the U.S. Department of Transportation that are sealed and not connected via interconnected piping to the production process train and that are used only for storage 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.6. The atmospheric vessels connected to the process system that contains a Class I liquid and the associated pumps must be reflected on the design*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			documents in listed in § 250.842(a)(1) through (4) and § 250.842(b)(3).
	(b) 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.	You must ensure that all atmospheric vessels are designed and maintained to ensure the proper working conditions for LSH sensors. The LSH must be designed in such a way to prevent pollution as required by § 250.300(b)(3) and (4). The LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality. For newly installed atmospheric vessels that have oil buckets, the LSH sensor must be installed to sense the level in the oil bucket.	*It is important to understand that the location of the LSH sensor is not the most relevant criteria. What is most important is that the vessel is designed to prevent pollution. Installing an LSH sensor in the oil bucket does not ensure that oil will not carry over and spill. Also, many atmospheric vessels are designed with the LSH sensor in the tank itself and are capable of preventing carry over and spillage. Therefore, the Joint Trades recommend that the following performance-based language be considered:* *You must ensure that all atmospheric vessels installed are designed and maintained to ensure the proper working conditions for LSH sensors. The LSH must be designed and installed in such a way to prevent pollution ~~as required by § 250.300(b)(3) and (4).~~ The LSH sensor bridle must be designed to prevent different density fluids from impacting sensor functionality. ~~For newly installed atmospheric vessels that have oil buckets, the LSH sensor must be installed to sense the level in the oil bucket.~~*
	c) You must ensure that all flame arrestors are maintained to ensure proper design function (installation of a system to allow for ease of inspection should be considered).	DELETE paragraph c	*OOC supports and agrees with the proposed deletion of 250.872(c).*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
§ 250.873 Subsea gas lift requirements	If you choose to install a subsea gas lift system, you must design your system as approved in your DWOP or as follows:	*****	
	(a) Design the gas lift supply pipeline in accordance with API RP 14C (incorporated by reference as specified in § 250.198) for the gas lift supply system located on the platform.	*****	
	(b) Meet the applicable requirements in the following table:	*****	*The Joint Trades recommend revising the following table accordingly (i.e. remove the references to ANSI/API Spec 6A) to reflect the recommended deletion of GLSDVs as SPPE. See Joint Trades comment at 250.802.*

Current Rule 250.873(b) Table

If your subsea gas lift system introduces the lift gas to the . . .	Then you must install a				In addition, you must
	API Spec 6A and API Spec 6AV1 (both incorporated by reference as specified in §250.198) gas-lift shutdown valve (GLSDV), and . . .	FSV on the gas-lift supply pipeline . . .	PSHL on the gas-lift supply . . .	API Spec 6A and API Spec 6AV1 manual isolation valve . . .	
(1) Subsea pipelines, pipeline risers, or manifolds via an external gas lift pipeline or umbilical	Meet all of the requirements for the BSDV described in §§250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (*i.e.,* within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical)	on the platform upstream (in-board) of the GLSDV	pipeline on the platform downstream (out board) of the GLSDV	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated	(i) Ensure that the MAOP of a subsea gas lift supply pipeline is equal to the MAOP of the production pipeline. (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. (iii) Install the GLIV downstream of the underwater safety valve(s) (USV) and/or AIV(s).

(2) Subsea well(s) through the casing string via an external gas lift pipeline or umbilical	Meet all of the requirements for the GLSDV described in §§250.835 and 250.836 on the gas-lift supply pipeline. Locate the GLSDV within 10 feet of the first point of access to the gas-lift riser or topsides umbilical termination assembly (TUTA) (*i.e.,* within 10 feet of the edge of the platform if the GLSDV is horizontal, or within 10 feet above the first accessible working deck, excluding the boat landing and above the splash zone, if the GLSDV is in the vertical run of a riser, or within 10 feet of the TUTA if using an umbilical)	on the platform upstream (in-board) of the GLSDV	pipeline on the platform down-stream (out board) of the GLSDV	downstream (out board) of the PSHL and above the waterline. This valve does not have to be actuated.	(i) Install an actuated, fail-safe-closed GLIV on the gas lift supply pipeline near the wellhead to provide the dual function of containing annular pressure and shutting off the gas lift supply gas. (ii) If your subsea tree or tubing head is equipped with an annulus master valve (AMV) or an annulus wing valve (AWV), one of these may be designated as the GLIV. (iii) Consider installing the GLIV external to the subsea tree to facilitate repair and or replacement if necessary.
(3) Pipeline risers via a gas-lift line contained within the pipeline riser	Meet all of the requirements for the GLSDV described in §§250.835(a), (b), and (d) and 250.836 on the gas-lift supply pipeline. Attach the GLSDV by flanged connection directly to the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser. To facilitate the repair or replacement of the GLSDV or production riser BSDV, you may install a manual isolation valve between the GLSDV and the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser, or outboard of the production riser BSDV and inboard of the API Spec. 6A component used to suspend and seal the gas-lift line contained within the production riser	upstream (in-board) of the GLSDV	flowline upstream (in-board) of the FSV	downstream (out board) of the GLSDV	(i) Ensure that the gas-lift supply flowline from the gas-lift compressor to the GLSDV is pressure-rated for the MAOP of the pipeline riser. (ii) Ensure that any surface equipment associated with the gas-lift system is rated for the MAOP of the pipeline riser. (iii) Ensure that the gas-lift compressor discharge pressure never exceeds the MAOP of the pipeline riser. (iv) Suspend and seal the gas-lift flowline contained within the production riser in a flanged API Spec. 6A component such as an API Spec. 6A tubing head and tubing hanger or a component designed, constructed, tested, and installed to the requirements of API Spec. 6A. (v) Ensure that all potential leak paths upstream or near the production riser BSDV on the platform provide the same level of safety and environmental protection as the production riser BSDV. (vi) Ensure that this complete assembly is fire-rated for 30 minutes.

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
§ 250.876 Fired and exhaust heated components	No later than September 7, 2018, and at least once every 5 years thereafter, you must have a qualified third-party remove and inspect, and then you must repair or replace, as needed, the fire tube for 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 the documentation available to BSEE upon request.	No later than September 7, 2018, and at least once every 5 years thereafter, you must have a qualified third-party inspect, and then you must repair or replace, as needed, the fire tube for 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 the documentation available to BSEE upon request.	*The Joint Trades recommend the following change to 250.876:* *No later than September 7, 2018, and at least once every 5 years thereafter, you must have ~~a~~ qualified ~~third-party~~ personnel inspect, and then you must repair or replace, as needed, the fire tube for 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 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 the documentation available to BSEE upon request.* *The recommended change is based upon the following justification:* *Revise the requirement for "qualified third party" for inspection. The term "qualified" is subject to interpretation, and the requirement for a third party to perform the inspection is not consistent with existing regulation.* *Heater treaters and many newer glycol reboilers are built to the ASME BPV Code. As such, they are required to be repaired, maintained and*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			inspected in accordance with API 510 pursuant to §250.851(1)(ii). If the requirement in §250.876 did not exist, the fire tube would be inspected as part of the pressure vessel inspection required under §250.851(1)(ii). Per API 510, that inspection would be performed by someone with API 510 certification. API 510 allows a certified API 510 inspector to be employed by the owner/user or a third party, and §250.851(1)(ii) does not require that inspector to be third party. Some operators have certified API 510 inspectors on staff that are used to perform their mandated API 510 inspections, so a requirement for the fire tube inspection to done by a third party would not be consistent with §250.851(1)(ii). *Some glycol reboilers, especially older ones, have maximum allowable working pressures (MAWP) below 15 psig so are not considered pressure vessels per §250.851(2). As such, those vessels would not fall under the requirements of §250.851(1)(ii). However, API 510, particularly the latest (10th) edition, does not preclude applying requirements of API 510 to vessels with an MAWP less than 15 psig. Therefore, it would be reasonable for inspection of a fire tube in these vessels to be performed by someone certified to API 510 as well. Additionally, the potential failure mechanisms for a fire tube will be similar regardless of whether the tube is*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			installed in a vessel with an MAWP above or below 15 psig. *Revising the term "a qualified third party" to "qualified personnel" should satisfy BSEE's desire for an inspection to be performed by someone with appropriate knowledge, experience and training. At the same time, it would be consistent with §250.851(1)(ii) by not requiring the inspector to be third party. Finally, it would take advantage of a standard already incorporated by reference without conflicting with it.*
§ 250.880 Production safety system testing	(a) Notification. You must:	*****	
	(1) Notify District Manager at least 72 hours before commencing production, so that BSEE may conduct a preproduction inspection of the integrated safety system.	Notify District Manager at least 72 hours before you commence initial production on a facility, so that BSEE may conduct a preproduction inspection of the integrated safety system.	*The Joint Trades agree and support the proposed changes.*
	(2) Notify the District Manager upon commencement of production so that BSEE may conduct a complete inspection.	*****	*To be consistent with the proposed language in 250.880(a)(1), OOC recommends that "initial" be added to 250.880(a)(2) so that it reads as follows:* *"Notify the District Manager upon commencement of initial production so that BSEE may conduct a complete inspection."*
	(b) Testing methodologies. You must:	*****	
	(2) Perform testing and inspection in accordance with API RP 14C, Appendix D (incorporated by reference as specified in § 250.198), and the additional	*****	*If the 8th Edition of API RP 14C is incorporated by reference as proposed in 250.198, then 250.880(b)(2) will need to be updated as follows:*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
	requirements found in the tables of this section or as approved in the DWOP for your subsea system.		*(2) Perform testing and inspection in accordance with API RP 14C, Appendix ~~D~~ I (incorporated by reference as specified in § 250.198), and the additional requirements found in the tables of this section or as approved in the DWOP for your subsea system.*
	(c) Testing frequencies. You must:	*****	
	(1) Comply with the following testing requirements for subsurface safety devices on dry tree wells:	*****	
	Item name. **Testing frequency, allowable leakage rates, and other requirements**	**Item name.** **Testing frequency, allowable leakage rates, and other requirements**	
	(i) PSVs. Annually, not to exceed 12 calendar months between tests. Valve must either be bench-tested or equipped to permit testing with an external pressure source. Weighted disc vent valves used as PSVs on atmospheric tanks may be disassembled and inspected in lieu of function testing. The main valve piston must be lifted during this test.	*****	*The Joint Trades recommend that alternatives for compliance, such as the use of API RP 510, be incorporated into this section. For a detailed discussion of the justification of alternate compliance methods for PSV testing refer to the Joints Trades comments in Appendix 2.* *Annually, not to exceed 12 calendar months between tests. Valve must either be bench-tested or equipped to permit testing with an external pressure source. The main valve piston must be lifted during this test. Weighted disc vent valves used as PSVs on atmospheric tanks may be disassembled and inspected in lieu of function testing.*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			As an alternative to lifting the main valve piston, you may request to follow an inspection program based upon the requirements of API RP 510 and API RP 576 provided you continue to test the PSV pilot annually not to exceed 12 calendar months between tests. Weighted disc vent valves on atmospheric tanks may also be included in an inspection program based upon the requirements of API RP 510 and API RP 576 in lieu of annual disassembly and inspection.
	(viii) Flame, spark, and detonation arrestors.	*****	
	Must be visually inspected annually, not to exceed 12 calendar months between inspections.	*****	*The Joint Trades recommend that 250.880(c)(3)(viii) be changed as follows:* *Must be visually inspected on intervals ~~not to exceed 12 calendar months between inspections~~ not to exceed 3 years, except for stack/spark arrestors on forced draft and natural draft fired components which shall be inspected not to exceed every 5 years. Inspection intervals may be extended beyond the periods specified here if a risk assessment indicates that longer intervals are appropriate.* *The recommended change is based upon the following: Visual inspection intervals for arrestors should be determined through risk assessments and statistical analysis for device failure probability. As stated in API RP 14C, "testing intervals should be adjusted based on analysis of the required testing records. Test*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			intervals may need to be shortened to maintain the reliability of the system in system subject to higher stresses (corrosion, heat, etc.) and the intervals may be extended where analysis indicates that extension of the interval will not degrade the system reliability". *Recent industry inspection records show that the arrestors were still fit for service after many years of service in the majority of applications. We feel these results highlight that an inspection interval of 12 calendar months is overly stringent.* *Lastly, the arrestor performance can be monitored, and issues detected by observing the operating conditions of the component on which it is installed.*
§ 250.901 What industry standards must your platform meet?	(10) API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), (as incorporated by reference in §250.198);	API STD 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension- Leg Platforms (TLPs), (as incorporated by reference in §250.198);	*Please note the correct title of the document should be API STD 2RD, Dynamic Risers for Floating Production Systems.*
§ 250.1002 Design requirements for DOI pipelines	(5) You must design pipeline risers for tension leg platforms and other floating platforms according to the design standards of API RP 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension Leg Platforms (TLPs) (as incorporated by reference in §250.198).	You must design pipeline risers for tension leg platforms and other floating platforms according to the design standards of API STD 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension Leg Platforms (TLPs) (as incorporated by reference in §250.198).	*Please note the correct title of the document should be API STD 2RD, Dynamic Risers for Floating Production Systems.*
§ 250.1003-1006		*****	*Subpart J (at 250.1004) includes safety device requirements for DOI pipelines. This is scope overlap with API RP 14C. 250.1004 does not*

Reference	Current Rule Language	December 2017 Proposed Rule	Joint Trades Comments
			mention PSV's, but 14C does. Otherwise, the two are compatible. As pipelines are governed by other regulations and organizations (DOI and DOT), there has always been a case that pipelines should be removed from the scope of API RP 14C.

Appendix 2
Joint Trades (API, OOC, NOIA)
December 2017 Proposed Production Safety Systems Revisions
Joint Trades Responses to BSEE Request for Comments on Specific Issues
January 29, 2018

1. **BSEE Request -** ***Documents incorporated by reference. (§ 250.198)***

This proposed rulemaking would update the incorporation by reference of superseded standards currently incorporated in Subpart H to the current edition of the relevant standard. This includes incorporating new or recently reaffirmed editions of a number of standards referenced in Subpart H, as well as replacing one standard currently incorporated in the regulations, that was withdrawn by API, with a new standard. However, BSEE is still evaluating the newer editions of these standards to analyze the specific changes between the incorporated editions and the current editions and to assess the potential impacts of those changes on offshore operations. BSEE may decide not to replace the incorporated edition of a specific standard before the publication of the final rule. BSEE is soliciting comments that will inform our decision on updating these standards, including comments on potential risks and costs associated with the new editions. BSEE will consider a number of factors in evaluating the current editions; primarily focusing how compliance with the current edition balances impacts on safety and protection of the environment and with costs and burdens. If BSEE decides to replace the incorporated documents with new editions in the final rule, the new editions would apply to all sections of 30 CFR part 250 where those documents are incorporated. BSEE may also make some conforming changes to the regulatory text in the final rule that were not identified in this proposed rule.

Joint Trades Comments:

Incorporating new standards, or new editions of currently incorporated standards, requires substantial review to 1) identify the changes in the new edition, and 2) evaluate those changes to determine the potential impact on current operations and future operations. As BSEE has requested in the preamble to the proposed Production Safety Systems rule, "BSEE is soliciting comments that will inform our decision on updating these standards, including comments on potential risks and costs associated with the new editions." Given the limitations of a 30-day comment period a comprehensive review of potential risks and costs could not be completed. However, the Joint Trades did perform a limited evaluation of the standards being proposed for incorporation be reference, and we support incorporating the proposed standards with two exceptions, API Recommended Practice (RP) 14C 8th Edition and API RP 500 3rd Edition. To be clear, the Joint Trades are not opposed to these standards, but more time is needed to fully evaluate the potential impacts from incorporating these standards into the rule, as well as determine potential costs associated with implementation. For those revised standards incorporated by reference, timing for implementation of the new standards must be clarified, especially for those facilities currently under construction at the time of the effective date of the final rule. Since not all proposed revised standards are impacted by timing, the Joint Trades have indicated the documents for which implementation timing must be clarified in Appendix 1. The comments provided in Appendix 1 and Appendix 3 provide more background.

2. BSEE Request - *Requirements for SPPE. (§ 250.802)*

During the implementation of the original final rule, a number of operators inquired about using existing inventory of BSDVs that meet the requirements of § 250.802, but are not certified. BSEE is considering an approach that would allow operators to use this existing inventory. We are requesting comments on how to allow this, including information on the size of existing inventory and timing for use of that inventory, as well as comments on an approach to allow for this.

Joint Trades Comments:

The Joint Trades recommend that BSEE allow the continued use of any non-certified equipment that an operator either 1) had in their physical possession at the effective date of the 2016 final rule, or 2) had signed a purchase order, or contract to purchase non-certified equipment, provided that the equipment met the requirements outlined in NTL 2009-G36 at the time of procurement.

It is important to note that prior to the 2016 final rule, BSDVs were required to meet the BSEE stipulations outlined in NTL 2009-G36. NTL 2009-G36 required the BSDVs to meet API Spec 6A, API Spec 6AV1, and have a fire rating of at least 30 minutes. The 2016 Production Safety Systems final rule only added the “certification” requirement that the valves be manufactured under an API Spec Q1 (or other) quality program. Most BSDVs are not “off the shelf” valves. Depending on size, these valves typically require long lead times ranging from 6-18 months for manufacturing. Because of this long lead time and the necessity to avoid extended shut-ins waiting on replacements, operators have maintained an inventory of replacement valves prior to the 2016 final rule. The inclusion of the “certification” in the 2016 final rule, rendered this inventory of valves obsolete and useless only because the valves lacked the Q1 certification, not because the valves were unsafe.

Additionally, in a previous proposed Production Safety Systems rulemaking dated August 22, 2013, (*Federal Register* Volume 78, Number 163, pg 52250), BSEE referenced a Technology Assessment and Research Project #272, *Allowable Leakage Rates and Reliability of Safety and Pollution Prevention Equipment* that was funded by BSEE’s predecessor agency, the Minerals Management Service. The project examined (in part) the leakage rates for surface safety valves (SSV), underwater safety valves (USV), and subsurface safety valves (SSSV) and the reliability of certified SPPE versus non-certified SPPE. One important finding highlighted in the report indicated that “there is no statistically significant difference in the proportion of failures between certified and non-certified surface safety valves. Given the conclusion in this research project, BSEE has not demonstrated, through statistics or failure data, the need to immediately render this existing inventory of non-certified equipment obsolete.

Also, BSEE (then MMS) set precedence similar to this in 1988 when the original SPPE regulation was enacted that applied to USVs, SSVs, and SSSVs. The 1988 version of 30 CFR 250.806(b) stated the following:

> *(1) Before April 1, 1988, you may continue to use and install noncertified SPPE if it was in your inventory as of April 1, 1988, and was included in a list of noncertified SPPE submitted to BSEE prior to August 29, 1988.*
>
> *(2) On or after April 1, 1988:*
>
> *a. You may not install additional noncertified SPPE; and*
> *b. When noncertified SPPE that is already in service requires offsite repair, remanufacturing, or hot work such as welding, you must replace it with certified SPPE.*

Therefore, BSEE should allow the continued use of any non-certified equipment that an operator either 1) had in their physical possession at the effective date of the 2016 final rule, or 2) had signed a purchase order, or contract to purchase non-certified equipment, provided that the equipment met the requirements outlined in NTL 2009-G36 at the time of procurement.

In addition to the discussion regarding BSDVs, the Joint Trades would also like to highlight a concern regarding the proposed requirements outlined in 30 CFR 250.802. GLSDVs in a departing application do not require adherence to the SPPE certification standards, leakage rates, and testing frequencies to the same extent as BSDVs, USVs, SSVs, or SCSSVs/SSCSSVs. These latter valves are held to these standards due to their criticality in protecting personnel and the environment, whereas a GLSDV is a different application using dry gas to aid in the flow assurance of well production. Furthermore:

a. GLSDV are installed in a departing capacity (direction of flow into the well). There is a check valve to prevent backflow.
b. There is no testing frequency or leakage rate requirements for GLSDV.
c. There is no mention of GLSDV in the 8th edition of API RP 14C.

d. There are no statistics or failure data to justify the proposed addition of GLSDV as SPPE.

3. BSEE Request - ***What SPPE failure reporting procedures must I follow? (§ 250.803)***

In addition to the specific proposals described below, BSEE is seeking input about how to revise the current language specifying what constitutes "failure" used in this regulation. In response to comments received on the previous proposed rulemaking, BSEE included this language in the previous Subpart H rulemaking. During implementation of the current rule, BSEE received a number of questions from industry asking for additional clarification of this language and of what specific equipment issues operators must report. BSEE is requesting comments on revising how "failure" is specified. The current § 250.803 states, "[a] failure is any condition that prevents the equipment from meeting the functional specification or purpose."

Operators are required to follow the failure reporting requirements from ANSI/API Spec. 6A for SSVs, BSDVs, and USVs and to follow ANSI/API Spec. 14A and ANSI/API RP 14B for SSSVs. BSEE seeks input on specifying what constitutes "failure" for the purposes of the reporting requirements under § 250.803. The documents incorporated by reference in § 250.803 have different definitions of failure or may not include a definition of failure at all. Given these various definitions of failure, BSEE is inquiring as to if it is appropriate to include a single description of what constitutes failure that applies to all of the SPPE covered in § 250.803? Or is it more useful to include various descriptions, based on the type of equipment?

Joint Trades Comments:

The Joint Trades are offering comments here and in Appendix 1 that recommend a new definition of SPPE failure that is based upon definitions in existing industry standards. Our recommendation provides clarity on the types of events that should be considered SPPE failures and does not include situations that are considered as routine repair and maintenance. The SPPE failure definition as proposed in 30 CFR 250.803 (a) in its broadest interpretation includes maintenance issues and, thereby, the reporting of maintenance and routine repair items creates an administrative burden on operators and the agency with no improvement to safety and protection of the environment.

When looking at the complete list of SPPE, BSEE must recognize that this equipment has certain "wear" parts that, over time under normal conditions, will wear to the point of needing replacement. When these parts do wear, some operators may then consider the SPPE device to "fail to meet the functional specification." Other operators disagree with this view and consider the wear part to be inclusive in the functional specification(s), meaning the SPPE is designed to wear. Further, it is important to highlight that most, if not all, of these wear parts can be and are replaced without removing the SPPE from service. Additionally, given the published requirements for replacing non-certified SPPE, we suggest aligning the failure reporting threshold with this same guidance. In addition, it is important to note that the preamble to the September 2016 Production Safety Systems final rule (*Federal Register*, Volume 81, Number 173) stated,

> *The final rule defines a failure as, "any condition that prevents the equipment from meeting the functional specification" This is intended to ensure that* ***design defects*** *are identified and corrected and that equipment is replaced before it fails* [emphasis added].

If the intention is to identify design defects that create safety and environmental risks, then clearly maintenance and/or wear issues should not be considered failures. Therefore, the definition of failure must be clarified.

The Joint Trades suggest revising the definition of SPPE failure to align with appropriate industry standards. For SSVs, USVs, BSDVs we are recommending API Spec 6A and API Std 6AV2. For SSSVs we are recommending API Spec 14A and API RP 14B. We are differentiating between surface and subsurface SPPE to align with the industry standards. In addition, we strongly recommend that BSEE and industry convene a workshop(s) to determine the best repository/clearinghouse for collecting failure data. Until a mutually-agreeable solution can be developed, we are recommending that failure reports be documented and maintained as described in the applicable API standards, and the failure reports be provided to BSEE on request.

Recommended regulatory changes to 30 CFR 250.803(a) are as follows:

> *For SSVs, USVs, and BSDVs that require remanufacture or offsite repair as defined in API Spec 6A and API Std 6AV2, you must follow the failure reporting requirements outlined in Section 8 of API Std 6AV2. Your initial failure notification report and subsequent failure analysis reports either from you or from the manufacturer as stipulated in Section 10.20.7.4 of API Spec 6A, must be made available to BSEE upon request.*

For SSSVs that require repair as defined in API Spec 14A and API RP 14B, you must follow the failure reporting requirements outlined in Section 8.4.2 and Annex B of API RP 14B. Your initial failure notification report and the subsequent failure analysis reports either from you or from the manufacturer as stipulated in Section 6.6 of API 14A, must be made available to BSEE upon request.

4. BSEE Request - *Considerations for failure reporting under § 250.803 What SPPE failure reporting procedures must I follow?*

BSEE is seeking input on clarifying when a failure analysis is required under § 250.803. Under what circumstances should BSEE require more failure analysis information? For example, a formal root cause failure analysis conducted by Subject Matter Experts, or the manufacturer? Should BSEE limit the formal failure analysis to cases where SPPE are returned to shore for remedial action to address the cause of the failure?

Joint Trades Comments:

Please reference our comments under response number 3.

5. BSEE Request - *Emergency action and safety system shutdown—dry trees. (§ 250.821)*

BSEE is proposing to revise paragraph (a) of this section to clarify that operators must shut in the production on any facility that "is impacted or that will potentially be impacted by an emergency situation." BSEE includes some examples of emergencies such as named storms, ice events in the Arctic, or earthquakes. It was not BSEE's intent to specify all emergency events that could trigger this regulation. The operator must determine when their facility is impacted or will potentially be impacted due to an emergency situation. The existing regulations do not clearly state that operators must shut in any facility that has been or may potentially be impacted by an impending emergency. The proposed clarification is to ensure that operators understand that they have an obligation to properly secure wells before the platform is evacuated in the event of an emergency. For example, if a well is capable of flowing and does not have a subsurface safety device, one must be installed. The current regulations require that this activity be done as soon as possible. BSEE requests comments on whether the phrase "as soon as possible" provides sufficient regulatory certainty or if there are more objective criteria, such as a before the facility is evacuated, that could be used to define these obligations.

Joint Trades Comments:

If BSEE's intent with this regulation is to require operators to secure the facility (and wells) following the prescribed method(s) and this is to occur prior to evacuation of the facility, then the regulation should so state. We suggest that 30 CFR 250.821 be revised to read:

> *If your facility is impacted or will potentially be impacted by an emergency situation (e.g., an impending National Weather Service-named tropical storm or hurricane, ice events in the Arctic, or post-earthquake), <u>you must complete the following activities prior to evacuation of the facility:</u>*

6. BSEE Request - *Platforms. (§ 250.841)*

The existing paragraph (b) of this section currently requires operators to maintain all piping for platform production processes as specified in API RP 14E Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems (API RP 14E). Section 6.5(a)(1) of API RP 14E addresses painting of steel piping to prevent corrosion. Corrosion prevention is important for safety and pollution prevention, and BSEE is not currently proposing to remove the reference to API RP 14E from this section. However, BSEE is interested in comments on whether other changes may be warranted. BSEE recognizes that there are difficulties accessing some of the piping on existing facilities, and BSEE is aware that operators have asked for extension, after BSEE has issued an incident of noncompliance, to provide additional time to implement this requirement on some facilities. In these cases, BSEE has generally requested that operators submit a departure request that includes an implementation plan to BSEE for complying with this section of API RP 14E. In the implementation plan, BSEE is looking for the operator to: 1) identify facilities for which extra time is needed for compliance, 2) specify areas of inaccessible piping, 3) address precautions taken until the piping can be accessed for painting, and 4) prioritize high-risk areas for more rapid treatment.

Joint Trades Comments:

The Joint Trades do not recommend any additional changes to 30 CFR 250.841. The information provided by BSEE regarding corrosion prevention departure requests appears to describe a process that is generally accepted and workable. If the current departure request process is accomplishing the objective of establishing implementation plans by exception to address corrosion on areas that are difficult to access, then we do not see a need to develop additional regulations.

7. BSEE Request - *Potential revisions to § 250.107(c) Best Available and Safest Technology (BAST)*

In the 2016 final rule, BSEE revised the definition of BAST contained in Section 250.107 based on public comments. BSEE solicits comments on whether this language adequately reflects the statutory mandate concerning the use of BAST on the OCS.

Joint Trades Comments:

While the current language at 250.107(c)(2) is straightforward in that compliance with the regulations is presumed to constitute the use of BAST, we are more concerned with the BAST Determination Process. The determination process, in its current form, appears to allow BSEE to require compliance with "new" BAST without BSEE following the rulemaking process.

In the event that BSEE determines that a new BAST Determination may be necessary, the agency may initiate the BAST Determination Process. The BAST Determination process consists of 3 main stages: (1) BAST Assessment and Initial Feasibility, (2) BAST Evaluation, and (3) BAST Determination. Each of these stages includes certain milestones and public notices; however, it is imperative that each stage, milestone, and public notice start with publication in the *Federal Register* allowing for stakeholder comment, thus ensuring transparency. Following such a process allows for publication of the problem statement along with supporting data for public review, analysis, and comments. Further, the Agency must publish for notice and comment its proposed action prior to issuing a final BAST determination. Additionally, BSEE must go through a full rulemaking process prior to mandating the use of any new technology on the OCS as a result of the BAST Determination Process. The failure of BSEE to include the rulemaking process (ANPRM, NPRM, FRM) in the BAST Determination Process, circumvents BSEE's requirement to allow for public review and comment, and BSEE's obligations to address those comments prior to issuing a final rule.

In addition, the Joint Trades also offer the following comments regarding 30 CFR 250.107(a)(3), which reads:

(a) You must protect health, safety, property, and the environment by:

(3) Utilizing recognized engineering practices that reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and

Although 30 CFR 250.107 (a)(3) was not specifically identified in BSEE's notice for comment, Industry strongly recommends that the phrase "to the lowest level practicable" be deleted from 30 CFR 250.107(a)(3) because: (1) it creates a contrary requirement to the BAST provision of 30 CFR 250.107 (c), (2) it was promulgated without a justification, cost-benefit, or burden analysis, (3) it unjustifiably exceeds existing and sufficient safety regulations, and (4) it runs contrary to the BAST regulatory standard specified in the Outer Continental Shelf Lands Act (OCSLA).

(1) In April 2016, BSEE issued a final rule for Oil and Gas and Sulfur Operations in the Outer Continental Shelf-Blowout Preventer Systems and Well Control Rule, being published in 81 Fed. Reg. 25888 and codified in 30 CFR Part 250 (hereafter, "Well Control Rule").

In September 2016, BSEE issued a final rule for Oil and Gas and Sulfur Operations on the Outer Continental Shelf-Oil and Gas Production Safety Systems, being published in 81 Fed. Reg. 61833 and codified in 30 CFR Part 250 (hereafter, "Production Safety Systems Rule").

Whereas the Production Safety Systems Rule included language clarifying the longstanding a Best Available and Safest Technology standard in 30 CFR 250.107(c) ("BAST"), the earlier Well Control Rule promulgated a contrary, undefined, and highly uncertain 'lowest level practicable' standard in 30 CFR 250.107(a)(3)) ("LLP"). Although BAST allows for a waiver for existing operations, LLP broadly applies to all OCS operations - both new and existing – without any provision for waiver (i.e. "…reduce risks to the lowest level practicable when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities"). Therefore, LLP and BAST are not consistent.

Furthermore, BSEE has not provided guidance as to what regulations or standards represent compliance with LLP; in contrast, the BAST rule specifically says that conformance with BSEE regulations is presumed to constitute use of BAST (see 30 CFR 250.107(c)(2)). Consequently, operators with comprehensive, effective safety-management systems and outstanding compliance records are now exposed to vague and possibly frivolous challenges regarding whether their systems conform to the regulatory LLP standard. As the regulator, BSEE is also subject to similar vagueness challenges as it tries to enforce these two, incongruent risk-reduction standards.

Thus, the contradictory regulations place both Industry and BSEE in an untenable compliance position.

(2) In promulgating the LLP standard, BSEE failed to provide a specific cost-justification for the proposed change, a cost-benefit assessment, or a burden analysis. These regulatory impact analyses are required by, among other things, Executive Order 12866 and OMB Circular A-4.

(3) BSEE has presented no data indicating that LLP adds any significant safety benefit, yet the vague LLP standard burdens companies with unnecessary and uncertain compliance challenges. The performance standards contained throughout the regulations –such as 30 CFR 250.107(a)(1), (b), and (c) of Subpart A and all of Subpart S – are more than sufficient to ensure effective safety and risk management. Therefore, eliminating LLP would be consistent with Executive Order 13771.

(4) Lastly, the Outer Continental Shelf Lands Act explicitly requires a 'Best Available and Safest Technology' standard for any 'safety and health regulations' promulgated under the act. LLP neither conforms to, nor is consistent with, this statutorily-mandated standard (see 43 U.S.C. 1347).

For the reasons stated above, the Joint Trades strongly recommend BSEE revise 30 CFR §250.107(a)(3) to read as follows:

> *Utilizing recognized engineering practices that reduce risks ~~to the lowest level practicable~~ when conducting design, fabrication, installation, operation, inspection, repair, and maintenance activities; and*

8. BSEE Request - ***Potential revisions to § 250.198 Documents incorporated by reference***

BSEE is considering potential, non-substantive revisions to § 250.198, as a whole, for the purposes of reorganizing and revising that section to make it clearer, more user-friendly, and more consistent with the Office of the Federal Register's (OFR's) recommendations for incorporations by reference in Federal regulations. BSEE will continue to consult with the OFR regarding its suggestions for specific organizational and language changes to § 250.198 and expects to address such revisions in a separate rulemaking as soon as possible. BSEE does not anticipate that those potential revisions would have any substantive impact on the proposed incorporations by reference of industry standards discussed in this notice.

Joint Trades Comments:

BSEE's request for input on this issue is non-specific in that it is unknown exactly what changes are being considered. The Joint Trades recommend that no additional changes be made to 30 CFR 250.198 until such time as those changes can be included in a Notice of Proposed Rulemaking. Once BSEE has consulted with OFR, any changes to 30 CFR 250.198 should be published for public comment through the rulemaking process.

9. BSEE Request - ***Extension of compliance for pressure safety valve (PSV) testing under § 250.880) Production safety system testing***

BSEE also considered revising the requirements regarding PSV testing in § 250.880(c)(2)(i). This existing provision requires operators to test PSVs annually and that the main valve piston must be lifted during this test. The main valve piston is a critical component of the PSV, and this approach will verify it will actually vent when needed. BSEE recognizes that this is a change to the approach used for testing prior to the 2016 rule and that some operators needed time develop new testing procedures. In some cases, operators may need to modify existing equipment or fabricate new equipment to fully comply. BSEE granted departures to this provision, giving operators who requested a departure under § 250.142, until November 7, 2018 to comply with this requirement. BSEE expects that operators will be able to comply by that date and a revision to this requirement is not needed; nevertheless BSEE is considering whether it is appropriate to provide additional time to perform the first required test on those PSVs where it is not possible to lift the piston during the test. BSEE would potentially consider an additional 1 to 2 years beyond the effective of this rulemaking for BSEE seeks comments on this issue, including comments on an appropriate time period for the delay.

Joint Trades Comments:

The Joint Trades recommend that the Production Safety Systems Rule explicitly provide an alternative method of verifying the functionality of PSVs. It is important that operators be given the option to employ other methods for ensuring PSV reliability. In our comments in Appendix 1, we offer the following recommended language for 30 CFR 250.880(c)(1)(i):

(i) PSVs

Annually, not to exceed 12 calendar months between tests. Valve must either be bench-tested or equipped to permit testing with an external pressure source. *<u>The main valve piston must be lifted during this test. Weighted disc vent valves used as PSVs on atmospheric tanks may be disassembled and inspected in lieu of function testing.</u>*

<u>As an alternative to lifting the main valve piston, you may request to follow an inspection program based upon the requirements of API RP 510 and API RP 576 provided you continue to test the PSV pilot annually not to exceed 12 calendar months between tests. Weighted disc vent valves on atmospheric tanks may also be included in an inspection program based upon the requirements of API RP 510 and API RP 576 in lieu of annual disassembly and inspection.</u>

The following discussion provides justification for including this alternative method. For pilot PSVs installed on offshore facilities with the PSV outlet connected to an emergency flare system, the primary evidence for main PSV piston movement while the PSV is installed is audible – can someone hear the main piston move. This "did you hear it move" standard can be challenging to demonstrate for the following reasons:

- The type of pilot matters; higher set pressures are more audible.
- Audible evidence can be difficult to detect in noisy areas of the facility.

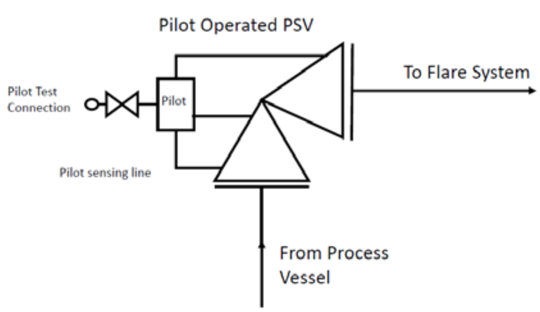
It is much easier to detect main piston movement by sound in a maintenance/repair shop environment with no outlet piping connected to the PSV. In the shop environment, one can easily hear the main piston movement and see the test media relieving from the PSV outlet.

For snap-acting pilots, it is much easier to move the main piston using the pilot test connection when a snap acting pilot is installed by simply exceeding the set point. The limiting factor may be a "too low" set pressure, or the ambient background noise which hampers audible detection.

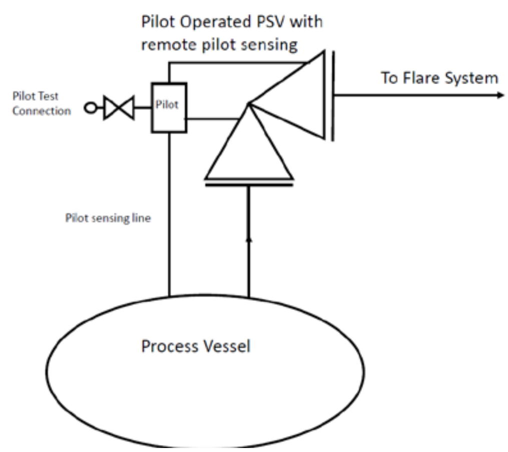
Modulating pilots are the most common type of pilot, because modulating pilots minimize the amount of flaring and allow for more efficient PSV pipe sizing; piping is sized for the design relief rate, not the maximum flow allowed by the PSV orifice when a modulating pilot is installed. It is more difficult to hear the main piston moving when a PSV with a modulating pilot is tested. The modulating pilot opens slowly in response to overpressure building up, not abruptly, like the snap acting pilot, so the amount of main piston movement will generally be more limited and more difficult to hear. Shop bench testing may be the only reliable approach for consistently verifying main piston movement in modulating pilot PSVs, especially in the noisier areas of the facility. Even when an inlet block valve is installed, which many operators do not currently have on their facilities, and test pressure is applied under the main PSV inlet, seeing the pressure fall off at set point may not indicate a main PSV piston movement. Test pressure can still be relieved through a flowing type pilot or faulty shuttle valve, although at a much lower flowrate (see Dwg #1 & #3 below). Pilot PSVs with remote pilot sensing lines connected directly to protected equipment are used when the PSV inlet piping pressure drop is high, or when the equipment being protected is subject to slugging or sudden pressure surge. Pilot PSVs with this installation configuration can only have their pilots tested in situ; an inlet block valve cannot be used to test (see Dwg #2). Potential unintended consequences of raising test pressure abruptly are additional flaring and damage to main piston seat/seals.

In refineries and petrochemical facilities, there generally are no annual in situ testing requirements. In those industries PSVs are bench-tested and inspected in accordance with API RP 510 (a standard that is already incorporated for other sections of the rule) and API RP 576. Any rebuilding or repairs are performed by a repair shop that has a VR stamp from the National Board of Boiler and Pressure Vessel Inspectors. This process is essentially the global standard for PSV preventative maintenance.

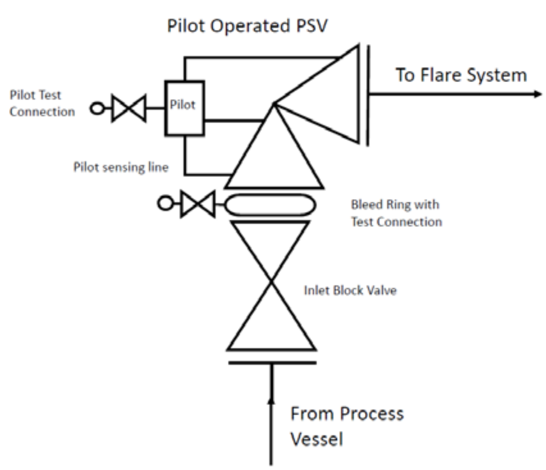
Dwg #1



Dwg #2



Dwg #3



10. BSEE Request - *Potential revisions based on the investigation of the explosion and fatality on West Delta Block 105 Platform E*

In 2016, BSEE issued a panel report entitled Investigation of November 20, 2014, Explosion and Fatality, Lease OCS-00842, West Delta Block 105 Platform E. The incident involved an explosion inside the electrostatic heater treater located on the platform while the contract cleaning crew personnel were engaged in activities related to cleaning the vessel. The report and corresponding memorandum, can be found at https://www.bsee.gov/wd-105-e-panel-report. We are seeking comments on the possibility of revising BSEE's regulations to address the recommendations in this report, including information on timing, costs, and other considerations. BSEE will consider relevant comments in developing any proposed rulemaking addressing the following topics from the report:

a) BSEE Request - Safety Device to De-Energize Electrostatic Heater Treater

Should BSEE consider requiring facilities to have a safety device able to detect a drop in the level of the coalescing section of electrostatic treaters and have the associated function of tripping the power to the transformer and/or grid if the level drops too low? How are the associated risks for similar equipment managed?

Joint Trades Comments:

The BSEE Panel Report on the West Delta 105 Platform E incident makes several recommendations in addition to installation of a safety device to de-energize electrostatic heater treaters. The Panel Report also recommends that operators ensure pre-job isolations and verification of isolations be performed correctly. Proper isolation and lockout/tagout procedures are already addressed in US Coast Guard Outer Continental Shelf regulations at 33 CFR 142.90. Proper use and implementation of these type of "lockout/tagout" procedures are a common practice among OCS operators. Requiring the addition of a redundant safety device to de-energize the electrostatic heater treater adds minimal additional protection since a heater treater should be properly de-energized prior to the start of any maintenance work. In addition, the Panel Report could not definitively state that electrical energy was the ignition source. The report states, "The BSEE Panel believes the probable cause of the ignition was the unrestricted supply of electrical energy to the electrostatic components inside the coalescing section of the heater treater. However, all other possible ignition sources could not be definitively eliminated." Therefore, it cannot be confirmed that the presence of such a safety device would have prevented the incident.

If BSEE were to require installation of level-safety devices to de-energize heater treaters, such a requirement would likely require significant modification and retrofit of existing heater treaters currently installed on the OCS. The cost-benefit of requiring such retrofits must be fully understood before enacting such a requirement. Including such a requirement in the final Production Safety Systems rule would require a re-evaluation under Executive Order 13771 to determine whether additional regulatory burden is being created.

Existing isolation procedures, proper training and awareness, and adequate ventilation of the enclosed space prior to beginning maintenance work (all of which are also recommendations in the Panel Report) are adequate controls for safely executing heater treater maintenance. All of these controls are already addressed by existing industry procedures and other agency regulations. The Joint Trades do not recommend including new requirements for redundant safety devices without a full and proper analysis of cost, operational impact and identification of other safety risks that may be associated with installation and use of such devices.

b) BSEE Request - Safe Cleaning Procedures for Tanks and Vessels

Do the existing BSEE regulations and standards provide adequate guidance regarding safety when performing cleaning activities on tanks or vessels that contain, or previously contained, petroleum or petroleum-related products? If not, what revisions to BSEE's regulations or incorporated standards are needed?

Joint Trades Comments:

Safe practices for planning and executing hydrocarbon tank and vessel cleaning are ubiquitous in the offshore oil and gas industry. Existing work practices are based upon regulation (e.g. For example, 29 CFR 1910.146 Occupational Safety and Health Administration Confined Space Entry regulations), industry standards (e.g. ANSI/API Recommended Practice 2016, Guidelines for Entering and Cleaning Petroleum Storage Tanks) and internal risk assessments and procedures executed by individual operators. Because a myriad of existing regulations and standards adequately address this topic, there is no need for BSEE to create additional regulations.

11. BSEE Request - *Implementation of this rulemaking*

BSEE seeks comments on potential obstacles for implementing the requirements in this NPRM; including the feasibility of implementation and any hardships operators may encounter during implementation.

Joint Trades Comments:

The comments contained in Appendix 1 include identification of obstacles and hardships operators may encounter during implementation of the proposed revisions to the Production Safety Systems rule. In addition to those comments in Appendix 1, we offer the following:

<u>Application of New Editions of Documents Incorporated by Reference to Existing Equipment</u> – BSEE must ensure that existing equipment designed, constructed and installed in accordance with codes and standards pre-dating the standards proposed for incorporation by reference are not adversely affected. Implementation of new codes and standards should be applicable only to new equipment designed, constructed and installed after the effective date of the final rule. In short, new standards should not be applied to existing equipment designed to previous codes. This approach is common in other regulatory programs and should be a practice adopted by BSEE.

<u>Sufficient Time to Implement the Final Rule</u> - Allotting sufficient time to implement the final rule is crucial to achieving compliance success. The proposed revisions to the rule are silent on the timing allowed for implementation of any final rule requirements. It is critical that BSEE fully understand the implications of what they will be tasking both industry and their own resources in undertaking and plan the implementation of the rule accordingly.

A sound approach would be to evaluate each change and determine appropriate compliance deadlines based on the magnitude of the change, the time required for BSEE to train its staff on the new requirements, the time required for operators to train and communicate the new requirements, and the need to make physical changes to the approximately 2400 offshore production facilities.

For example, the proposed changes to documents that require a professional engineering seal is relatively straightforward as they require no physical changes to facilities and can likely be implemented quickly (e.g. within 60 days from publication). However, the proposed change in 30 CFR 250.198 to incorporate the 8th Edition of API Recommended Practice 14C (API RP 14C) will have additional impacts that will require a longer implementation timeframe. The Joint Trades have included comments and concerns regarding API RP 14C in Appendix 3.

The minimal amount of time industry was allocated to implement the current Production Safety Systems rule published in September 2016 resulted in numerous requests to BSEE for alternate approaches to achieve compliance. BSEE must take steps to ensure that a similar situation does not occur again. The Joint Trades are very interested in providing recommendations to BSEE on appropriate implementation timelines for the proposed changes to the rule, but, as discussed earlier, more time than the allotted 30-day comment period is needed to develop this type of input.

Insufficient Time to Assess Risk, Costs and Burdens – As discussed several times in these comments, BSEE desires input on risks, costs and burdens resulting from the proposed Production Safety Systems revisions. The Joint Trades were unable to provide that information in detail because of insufficient time allocated for the comment period.

Appendix 3
Joint Trades (API, OOC, NOIA)
December 2017 Proposed Production Safety Systems Revisions
Incorporation of API Recommended Practice 14C Comments
January 29, 2018

The Joint Trades performed a review of the changes to API Recommended Practice (RP) 14C, 8th Edition. We recommend that API RP 14C, 8th Edition, not be incorporated by reference until a more thorough review of costs and operational impacts is completed. API RP 14C, 8th Edition has changed substantially from prior editions, and the proposed changes and associated impacts are not fully understood across the industry. The information provided in this Appendix provides a cursory overview of some of the new requirements contained in the 8th Edition and identifies questions and concerns that need evaluation.

If BSEE's intent for the proposed Production Safety Systems Rule is to reduce regulatory burden, then the agency also must carefully consider the potential impacts from incorporating API RP 14C, 8th Edition. The 8th Edition requires the addition of several new safety devices on various types of equipment, as well as two new valve tests. These changes to API RP 14C, if incorporated by reference and made mandatory by regulation, have the potential to impact the cost and burden associated with the proposed regulatory changes, thereby creating a need for the agency to reassess its regulatory cost analysis.

If BSEE decides to incorporate API RP 14C, 8th Edition as proposed in the Production Safety Systems revisions, then the agency should consider the potential impacts to existing facilities that were designed, constructed and installed under prior editions of API RP 14C. Implementation of new codes and standards should be applicable only to equipment designed, constructed and installed after the effective date of the final rule. In short, new standards should not be applied to existing equipment designed to previous codes. This approach is common in other regulatory programs and should be a practice adopted by BSEE.

Summary of Changes & Potential Issues

The information below provides a brief overview of some of the changes and new guidance included in API RP 14C, 8th Edition. Highlighted text indicates new recommendations included in the 8th Edition. Each section is followed by questions and/or issues that will need to be addressed prior to implementation.

5.1 Pupose and Objective

5.1.2 However, it is incumbent on the user to apply appropriate additional hazard analysis methodologies to ensure that hazards are identified and mitigated.

<u>Questions/issues</u>: This would potentially require a change to an operators SEMS Hazard Analysis procedure.

5.13 Before a production facility safety system is placed in operation, procedures should be established to ensure continued system integrity. Annex B may be used for this purpose.
<u>Questions/issues</u>: 8th Edition, Annex B describes how to create a SAFE Chart. Evaluation is needed to determine whether the SEMS Hazard Analysis procedures should include requirements for a SAFE Chart Review.

5.4 Premises for Basic Analysis and Design

5.4.5 Process connections between control and safety devices should be independent to eliminate common cause failures. For example, the LSH and the level control device would have separate process connections for high level in a vessel.

<u>Questions/issues</u>: Would a bridle be considered a process component as defined 3.1.60? If yes, then as long as the LSH and level control device have separate connections to the bridle and can be isolated and tested independently, then this would be acceptable. If no, then an evaluation of each bridle would be necessary to determine common cause failures. Will previous installations be "Grandfathered" or will this become retroactive and corrections need to be made or will "Locking Open" the bridle isolation valves suffice?

5.4.8 However, it is incumbent on the user to apply appropriate additional hazardous analysis methodologies to ensure that hazards are identified and mitigated.

<u>Questions/issues</u>: Further clarification of this language is needed. This would potentially require a change to an operators SEMS Hazard Analysis procedure.

5.4.10 The safety system should be designed to limit the amount of time and frequency that safety functions are bypassed and to automate start-up bypasses where practical to minimize human error. Bypasses shall be classified and applied in accordance with Annex C.

<u>Questions/issues</u>: Need to cross review new Annex C Remote Operations to existing NTL 2009-G24 for SCADA Systems to see if there are any differences and determine the impacts of those identified differences vs currently BSEE approved SCADA Systems. If there are differences, will existing installations be grandfathered? Will Annex C supersede NTL 2009-G24 and will the NTL become inactive once the revised 14C is in effect?

6.2.4 Protective Shut-in Action
6.2.4.4 Where pipelines are a potential source of pressure or backflow (e.g. gas pipelines or where pipelines have multiple downstream input sources), the pipeline-tested SDV/FSV should have a leakage rate as specified per 1.4.10 to ensure that leakage through a closed valve will not lead to significant escalation from an ignited release. This ensures the maximum level of safety for the production facility and the people aboard the facility.

Questions/issues: Each existing pipeline SDV/FSV may require piping modifications in order to perform testing to meet this new testing requirement. The test paperwork will require modifications to include these monthly tests.

6.2.4.5 A TSE or other fire detection shall be installed to allow detection of a fire on pipeline-tested SDV/FSV.

Questions/issues: Each existing pipeline SDV/FSV will require the installation of a TSE in order to meet this new requirement.

A.2.3.3 Shutdown Devices (SSV or USV)
The SSV should be located on the wellhead as the first automatically actuated valve in the flow stream from the wellbore. The SSV should be actuated by the flowline pressure sensors, ESD system, fire detection system, and sensors on downstream process components. An SDV (in addition to the SSV) may be installed on the wellhead. If an SDV is installed, it may be actuated, in lieu of the SSV, by the flowline pressure sensors and sensors on downstream process components. The USV should be actuated by the Flowline pressure sensors located upstream of the BSDV, by the ESD system, and by the fire detection system.

Questions/issues: How will this be implemented since a SDV is not leak tested?

A.8.2.2.2 Pressure Safety Devices (PSH, PSL, and PSV)

A suction PSV should be provided on all pumps where backflow is possible, either through the pump or the recycle line, for overpressure protection due to backflow unless the suction piping and components have an MAWP greater than or equal to the pump discharge PSV set point, or the discharge piping is not rated higher than the suction piping, or the suction piping is protected by a PRD on an upstream component that cannot be isolated from the pump. A suction PSV is not required on glycol-powered glycol pumps.

Questions/issues: PSV(s) will likely need to be installed on many pumps that currently do not have PSVs.

Table A.16—Safety Analysis Checklist: Pumps
A.7f. PSVs—discharge of other pumps.
1) PSV installed.
2) Maximum pump discharge pressure is less than the MAWP of discharge piping.
3) Deleted in Eighth Edition.

Current reference: A.7f.3 Pump has internal pressure relief capability.

Questions/issues: Some SAFE charts will need to be updated.

A.7i. Low-flow sensor (FSL)—all pumps.
1) FSL installed.
2) The pump is a positive displacement type.
3) Pump is manually operated and continuously attended.
4) Low-volume pumps.
5) No low continuous flow (restricted or blocked flow) scenario.
6) A properly designed recycle system is installed.
7) PSH and/or PSL have trip set points selected to detect loss of flow.

Questions/issues: FSL will need to be added to some pumps.

A.7j. High-vibration sensor(s) (VSH).
1) VSH installed.
2) Pump with driver less than 1000 hp.
3) Pump is manually operated and continuously attended.

Questions/issues: Existing device that currently is not subject to BSEE inspection and oversight.

A.7k. Low-level sensor (LSL)—centrifugal seal buffer pot.
1) LSL installed.
2) Pump with driver less than 1000 hp and in nonvolatile service.
3) Pump is manually operated and continuously attended.
4) Pump has a secondary gas seal with failure detection pump shutdown.
5) Seal buffer pots not installed.

Questions/issues: No longer considered utility, but part of the process equipment.

A.7l PSH—centrifugal seal buffer pot.
1) PSH installed.
2) Pump with driver less than 1000 hp and in nonvolatile service.
3) Pump is manually operated and continuously attended.
4) Pump has a secondary seal with failure detection pump shutdown.
5) Seal buffer pots not installed.

Questions/issues: No longer considered utility, but part of the process equipment.

A.9 Compressor Units

A.8g. Check valve (FSV)—discharge.
1) FSV installed at discharge of each compressor unit.
2) FSV installed at final stage discharge and compressor is positive displacement type.

Questions/issues: Some SAFE charts will need to be updated.

A.8i. High-vibration sensor(s) (VSH).
1) VSH installed.
2) Compressor is manually operated and continuously attended.

Questions/issues: Existing device that currently is not subject to BSEE inspection and oversight.

A.8j. Secondary seal with FSH on primary seal vent—centrifugal and screw compressors.
1) Compressor less than 1000 hp and non-vapor recovery service.
2) Compressor is manually operated and continuously attended.
3) Secondary seal with failure detection and shutdown.
4) Compressor does not have dry gas seals.

Questions/issues: Existing device that currently is not subject to BSEE inspection and oversight.

A.10 Pipelines

a For departing pipelines, where significant backflow hazards exist from gas pipelines or where pipelines have multiple downstream input sources, backflow safety devices shall be a tested FSV or SDV.

Questions/issues: This is a new testing requirement.

A.11 Heat Exchangers

A.10d. Temperature safety high (TSH).
1) TSH installed.
2) Input source to heat exchanger section cannot develop temperature greater than the maximum allowable working temperature of the heat exchanger section.

Questions/issues: This is a new requirement, however, most likely currently installed if needed in the design.

A.10e. Temperature safety low (TSL)
1) TSL installed.
2) Input source to heat exchanger section cannot develop temperature lower than the minimum allowable working temperature of the heat exchanger section.

Questions/issues: This is a new requirement, however, most likely currently installed if needed in the design.

Annex B Examples of SAFD and SAFE Charts
There have been changes made to the example SAFE Chart. Two such notables are the following:

- KAH-1000 Departing Oil Pipeline PSHL:
    - Old 7th Edition: Only shut off oil pipeline pump. Thus, allowing cascading to the LSH on the oil storage tank to shut in the platform. NOTE: This example in the eyes of some BSEE Districts, not all, was the 4th acceptable method of cascading, because it was listed in 14C.
    - New 8th Edition: The PSHL now shuts in all of the input sources, i.e. wells, incoming pipelines & the pipeline pump.

Questions/issues: Will existing platforms SAFE Chart and safety systems be "grandfathered" in? Not sure how many facilities would be impacted.

- EAW-100 Fired Component (Natural Draft) Heater Treater TSH-1 Stack:
    - Old 7th Edition Figure E-2.3: Only shut in EAW-100.
    - New 8th Edition Figure B-5: Shuts in wells and shut off burner fuel gas.

Questions/issues: This impacts the SAFE Chart and safety system design. There are multiple existing facilities that may be impacted by this change.

Annex D Safety System Bypassing
Manual bypasses should inhibit trip functions, but shall not inhibit the associated trip alarms.

Questions/issues: This is a new requirement. Many pneumatic panels not currently installed in this manner.

Annex E High-Integrity Pressure Protection Systems

Questions/issues: This is a new section; this section may have an impact to an operators SEMS program pertaining to hazard analysis protocols.

Annex F Logic Solver

Questions/issues: This is a new section that creates many new requirements and requires additional documentation.

Annex G Emergency Support Systems

G.2.1.2 Shutdown Stations

i) within the process area, the maximum travel distance from any normal access deck location on the facility to ESD stations should not exceed 100 ft (30.5 m) as measured along main egress routes;

Questions/issues: This is a new requirement that needs to be evaluated for operational impact.

G.2.3.2 Installation

Pressure-sensing devices, in some cases, are only capable of detecting large leaks. The use of gas detectors in open process areas should be considered so that the ESS is capable of detecting gas releases such that the likelihood of escalation is minimized. Like a PSL, an automatic corrective action on confirmed gas by the detection system shall be targeted for the hazard that is being protected against in each area.

Questions/issues: This is a new requirement that needs to be evaluated for operational impact; may require a study of Class I, Division II areas.

Table G.1—Guidelines for Fusible Plug Installations

Atmospheric vessels - One for each 5 ft of perimeter to a maximum of 10 at the top of the vessel

Current standard – One for each vessel process inlet, outlet, and hatch.

Questions/issues: Likely a significant impact; a significant number of existing tanks would require modification.

G.2.6 Sumps

G.2.6.1 General

A sump may be a tank, a closed-end pile, or an open-end pile. All sumps should be equipped with an
automatic discharge to handle maximum inflow. Vents are installed on atmospheric sumps for the purpose of safely dissipating hydrocarbon vapors. Depending upon design and location, a sump pile vent may fulfill this purpose without a flame arrestor being installed. Due to possible plugging from corrosion, the low flow/low pressure (no static electricity), and distance from potential ignition/flash back sources, a flame arrestor could be eliminated in a sump pile located close to the water level.

Questions/issues: New requirement that needs to be fully evaluated for operational impacts.

G.2.6.2 Open-end Sump Piles

Properly designed open-end sump piles are occasionally used to collect deck drainage or drips and to dispose of treated produced water. Except during emergency upset condition, vessels should not discharge liquid hydrocarbons directly into an open-end sump pile. Open-end sump piles should be protected against hydrocarbon discharge (overflow and/or underflow). The type of protection should be determined on a case by- case basis. Some factors that should be considered include pile length, liquid properties, maximum inflow rate, wave action, and tidal fluctuation.

<u>Questions/issues</u>: This change may need more evaluation to ensure alignment with other regulatory requirements.

G.3.2 Hydraulic Supply System
G.3.2.2 Hydraulic Supply Properties
Proper functioning of the safety system is dependent on the hydraulic supply; therefore, a reliable and high quality hydraulic supply is essential. Maintaining the cleanliness of the hydraulic supply is fundamental to ensuring the reliability of the system.

<u>Questions/issues</u>: New requirement that needs to be fully evaluated for operational impacts.

G.3.2.4 Supply and Response
The hydraulic supply distribution systems should be sized to ensure adequate volume and pressure to all safety devices. For valve actuation, capacity should be such that the operating volume between maximum and minimum levels shall hold the complete control system capacity plus 20 %. Hydraulic supply usage should be calculated for the maximum condition that could be experienced at any one time. The time it takes for any safety device (e.g. PSH, BSL, ESD station, etc.) to effect component or facility shutdown should not exceed 45 seconds. To achieve this response, consideration should be given to hydraulic feed line sizes, safety device bleed port size, the use of auxiliary quick bleed devices, and hydraulic return line sizes.

<u>Questions/issues</u>: New requirement that needs to be fully evaluated for operational impacts; some systems may require physical modification.

G.3.5 Essential HVAC System
G.3.5.2 Design Considerations
The essential HVAC should be powered from the standby electrical power system. Replenishment air should be drawn from a deemed safe area. If gas is detected at air intakes or doorways, the system should, as a minimum, be capable of shutting off the external air supply to mitigate the likelihood of gas ingress.
<u>Questions/issues</u>: New requirement that needs to be fully evaluated for operational impacts.

Annex H Toxic Gases
H.2.4 H2S gas detecting sensors should be installed at the following locations.
b) In occupied buildings or spaces (e.g. at air intakes) located on facilities where toxic gas detectors are
installed.

Current standard says “buildings where personnel regularly or occasionally sleep“

<u>Questions/issues</u>: New requirement expands scope to all occupied buildings instead of sleeping quarters; needs more evaluation for potential impacts.

Annex I Testing and Reporting Procedures

I.2.1 Purpose

When re-commissioning a facility after being shut in for 30 days or more, the production safety system sensors and final elements shall be physically verified for proper operation. This verification is to ensure that all sensors remain connected to the process and are functioning and all final elements are properly connected and functional.

Questions/issues: New requirement that needs to be fully evaluated for operational impacts.

Where an addition or modification is made to the facility safety system, that portion of the system that has been added or modified and any portion of the system associated with that change shall be completely inspected and tested to ensure functionality from sensor through logic and to confirm that the final elements function as required.

Questions/issues: How will the term "system associated with" be interpreted?

Application code or configuration for the logic solver shall be strictly controlled under an MOC program.

Questions/issues: This may imply a requirement to conduct additional maintenance of panel drawings.

Table I.1, Item R Export Pipeline FSV & SDV leak Testing Requirements

New requirements to leak test the departing pipeline FSV or SDV (if installed); max allowable leak rate is 400 cc/min and 15 cu ft gas/min.

Questions/issues:

- *This is the same leak rate allowed for surface wellhead SSV's and subsea flowline BSDV's, which are typically robust gate valve designs that are better designed to meet a long-term service life of virtually zero leakage.*
- *Export pipeline SDVs are typically soft-seated ball valves which generally will not meet these leak test requirements after a few years of service.*
- *Most export pipeline valves were not selected or configured to facilitate reliably meeting these leak test requirements.*

Export pipeline check valves and export pipeline SDVs often have only a single ball valve to isolate them from the volume and pressure of the pipeline. Most operators would require double block & bleed to break containment adjacent to the pipeline to make a valve repair, which means that the pipeline will likely need to be shut-in and blown down to service these valves if they do not meet these leak test requirements. This will cause deferment for the asset needing the repair and all other customers that feed into that pipeline.

8th Edition Reference Changes in the Production Safety Systems Regulations

In addition to the potential operational impacts, API RP 14C, 8th Edition, changed section numbering and annex designations. Many annexes and sections are referenced specifically throughout the Production Safety Systems Rule. Therefore, references in 30 CFR 250 will require updating if the 8th Edition is incorporated by reference. The Joint Trades have identified the following 30 CFR 250 sections that would need revision if API RP 14C is incorporated by reference. This is not intended to be an all-inclusive list, only those items that were identified during our limited time for review.

- Section 250.852 references A.2; A.2 changed to A.1 in the 8th Edition.
- Section 250.855 references Appendix C; Appendix C changed to Annex G in the 8th Edition.
- Section 250.858 references sections A.4 and A.8; A.4 and A.8 changed to A.5 and A.9 in the 8th edition.
- 250.869 references Appendix C; Appendix C changed to Annex G in the 8th Edition.
- Section 250.872 references section A.5; A.5 changed to A.7 in the 8th Edition.
- Section 250.873 references designing to API RP 14C; this reference should be updated to API RP 17V since API RP 14C only covers dry tree injection lines.
- Section 250.874 references designing to API RP 14C; this reference should be updated to API RP 17V.