May 17, 2017

Katharine MacGregor
Acting Assistant Secretary Lands and Minerals Management
U.S. Department of the Interior
1849 C Street, NW
Washington, DC 20240

Re: Secretarial Order 3350 & Blowout Preventer Systems and Well Control

Via email

Dear Acting Assistant Secretary MacGregor:

The American Petroleum Institute (API), the International Association of Drilling Contractors (IADC), the Independent Petroleum Association of America (IPAA), the National Ocean Industries Association (NOIA), the Offshore Operators Committee (OOC), the Petroleum Equipment & Services Association (PESA), and the US Oil and Gas Association are pleased to see the Administration and the Department of the Interior (DOI) continuing to take strides to put in place a lasting, domestically-focused energy policy that will help the U.S. "maintain the Nation's position as a global energy leader." For too long the U.S. has been hampered by the lack of a strong domestic oil and natural gas energy policy. The oil and natural gas industry is committed to developing and producing domestic energy resources for the benefit of all Americans and doing so in a safe and environmentally sound manner.

Secretarial Order 3350, America-First Offshore Energy Strategy, which implements Executive Order 13795, is an important step forward that will help the offshore oil and natural gas industry regain the cost-effective regulatory framework that promotes the certainty and predictability necessary to make the massive capital investments required to bring offshore energy projects to the U.S. economy. This will serve to further the Department's stated goal "to ensure that responsible OCS exploration and development is promoted and not unnecessarily delayed or inhibited." This letter is intended to provide detailed information on the final Blowout Preventer Systems and Well Control rule to inform the regulatory and policy review directed by the order and to offer any needed assistance to you as DOI continues to implement Secretarial Order 3350.

The Final Well Control Rule is greatly improved from the proposed rule, but numerous concerns still remain. Industry has outlined our concerns in detail in the following table but wish to highlight four major concerns, in no particular order. Industry remains concerned with the drilling margin requirements in the final well control rule and suggests deleting the new regulatory text and reverting to the previous requirements. That risk-based approach to managing drilling margin in combination with existing regulatory oversight has been demonstrated to safely and economically drill wells. The requirements that exceed the provisions of API Standard 53 (API 53), Blowout Prevention Equipment Systems for Drilling Wells are unnecessary, will not improve safety and will increase risks to operations, which is why, we recommend using the requirements in API 53 as the primary best practice. Rulemaking on RTM is premature, we suggest deleting those requirements. And finally, Industry does not see the need for BSEE to require certification by BSEE-approved verification organizations (BAVOs). Certification can be done by third party organizations; they do not need to be approved by BSEE.

Safety is a core value for the oil and natural gas industry. We are committed to safe operations and support effective regulations in the area of blowout preventer systems and well control. We appreciate the actions of this Administration to eliminate unnecessary burden and to restore certainty and predictability into the offshore permitting and regulatory regimes. We look forward to continued engagement with the Department and you on these important regulatory requirements to assure that the energy that is fundamental to our society can be developed and delivered safely.

Thank you for your consideration of these comments, please do not hesitate to contact us if you have any questions.

Sincerely,

Holly Hopkins, API

Alan Spackman, IADC

Daniel Naatz, IPAA

Randall Luthi, NOIA

Evan Zimmerman, OOC

Leslie Beyer, PESA

Alby Modiano, US Oil and Gas Association

cc: Counselor to the Secretary for Energy Policy Vincent DiVito
BSEE Director
Doug Morris, Chief Office of Offshore Regulatory Programs, BSEE
Lars Herbst, GOM Regional Director, BSEE
Kirk Malstrom, Regulations and Standards Branch, BSEE

Attachment

INDUSTRY ASSESSMENT OF THE BSEE FINAL WCR

CFR Reference	Final Rule Language	Discussion	Suggested Clarification / Interpretation OR Revised/Alternative Reg Text
Provisions to Remove			
§ 250.198 (h)(70)	(70) ANSI/API Specification 6A, Specification for Wellhead and Christmas Tree Equipment, Nineteenth Edition, July 2004, including Errata 1 (September 2004), Errata 2 (April 2005), Errata 3 (June 2006), Errata 4 (August 2007), Errata 5 (May 2009), Addendum 1 (February 2008), Addenda 2, 3, and 4 (December 2008), incorporated by reference at §§ 250.730, 250.806, and 250.1002;	Redundant requirement to API 53.	Delete
§ 250.198 (h)(90)	(90) ANSI/API Specification 16A, Specification for Drill-through Equipment, Third Edition, June 2004, Reaffirmed August 2010, incorporated by reference at § 250.730;	Current edition but errata published. Relevant sections and appropriate edition of API Spec 16A are incorporated through the CFR requirement to meet API 53.	Delete
§ 250.198 (h)(91)	(91) ANSI/API Specification 16C, Specification for Choke and Kill Systems, First Edition, January 1993, Reaffirmed July 2010; incorporated by reference at § 250.730;	API Spec 16C 2nd ed. current basis for product manufacture. Relevant sections and appropriate edition of API Spec 16C are incorporated through the CFR requirement to meet API 53.	Delete
§ 250.198 (h)(92)	(92) API Specification 16D, Specification for Control Systems for Drilling Well Control Equipment and Control Systems for Diverter Equipment, Second Edition, July 2004, Reaffirmed	Current edition which is the basis for product manufacture. Relevant sections of API Spec 16D are incorporated through the CFR requirement to meet API 53.	Delete

	August 2013, incorporated by reference at § 250.730;		
§ 250.198 (h)(93)	(93) ANSI/API Specification 17D, Design and Operation of Subsea Production Systems—Subsea Wellhead and Tree Equipment, Second Edition; May 2011, incorporated by reference at § 250.730; and	Current edition but errata/addendum published. Relevant sections and appropriate edition of API Spec 17D are incorporated through the CFR requirement to meet API 53.	Delete
§ 250.198 (h)(94)	(94) ANSI/API Recommended Practice 17H, Remotely Operated Vehicle Interfaces on Subsea Production Systems, First Edition, July 2004, Reaffirmed January 2009, incorporated by reference at § 250.734.	Current edition but errata published. Relevant sections and appropriate edition of API Spec 17H are incorporated through the CFR requirement to meet API 53.	Delete
§250.414(c)(2)	(2) In lieu of meeting the criteria in paragraph (1)(ii), you may use an equivalent downhole mud weight as specified in your APD, provided that you submit adequate documentation (such as risk modeling data, off-set well data, analog data, seismic data) to justify the alternative equivalent downhole mud weight	Revert to pre-WCR text or adopt regulatory text proposed by industry review with OMB in response to WCR.	Delete or replace with: (3) If you use a lower margin that set forth in paragraph (c)(2), you must submit documentation (for example – a risk assessment, offset well data, or analogous well data) to support the drilling margin in: (i) your APD; or (ii) for field wide applicability, in advance of APD preparation, incorporate in your DOCD or Exploration Plan.
§250.427 (b)	While drilling, you must maintain the safe drilling margins identified in § 250.414. When you cannot maintain the safe margins, you must suspend	This requirement is outlined in 250.414 and this section is redundant.	Delete or replace with: (b) While drilling, you must maintain the safe drilling margin identified in the approved APD.

	drilling operations and remedy the situation.		When you cannot maintain the safe margins, you must suspend drilling operations and remedy the situation.
§ 250.724	**What are the real-time monitoring requirements?** (a) No later than April 29, 2019, when conducting well operations with a subsea BOP or with a surface BOP on a floating facility, or when operating in an high pressure high temperature (HPHT) environment, you must gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting data regarding the following: (1) The BOP control system; (2) The well's fluid handling system on the rig; and (3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed). (b) You must transmit these data as they are gathered, barring unforeseeable or unpreventable interruptions in transmission, and have the capability to monitor the data onshore, using qualified personnel in accordance with a real-time monitoring plan, as provided in paragraph (c) of this section. Onshore personnel who monitor real-time	Implementation of the proposed prescriptive real time monitoring requirements has the potential to shift decision-making authority away from Operators and their rig site personnel. The increased engagement of BSEE in ongoing operations could distort the lines of responsibility and accountability, and create confusion that could decrease overall operations integrity. It is critical that regulations ensure that Operators have clear authority for their respective operations and that the rules focus on specifying the range of risks that need to be addressed. During any given operation the onsite personnel have the best understanding and most complete picture of the current operation, key risks, and critical considerations. In addition, their experience in active operations best positions them to make effective real-time decisions within the bounds specified by the Operator's governing procedures and operations	Delete

	data must have the capability to contact rig personnel during operations. After operations, you must preserve and store these data onshore for recordkeeping purposes as required in §§ 250.740 and 250.741. You must provide BSEE with access to your designated real-time monitoring data onshore upon request. You must include in your APD a certification that you have a real-time monitoring plan that meets the criteria in paragraph (c) of this section. (c) You must develop and implement a real-time monitoring plan. Your realtime monitoring plan, and all real-time monitoring data, must be made available to BSEE upon request. Your real-time monitoring plan must include the following: (1) A description of your real-time monitoring capabilities, including the types of the data collected; (2) A description of how your realtime monitoring data will be transmitted onshore during operations, how the data will be labeled and monitored by qualified onshore personnel, and how it will be stored onshore; (3) A description of your procedures for providing BSEE access, upon request, to your real-time monitoring	integrity guidelines. This role includes full control of the operations and the full authority to stop activities at any time. Utilizing shore base decision-making from real-time data centers, as indicated by the proposed rules, has the potential to decrease offshore personnel's authority which is critical to maintaining safe operations and responding to emergency situations. In times of communication interruptions or significant offshore events (well control, station keeping difficulties, vessel collisions, equipment failure, etc.) there is generally insufficient time to interact with shore base command centers to plan or seek approval for an immediate response. In these critical moments, offshore supervision is key, and its effectiveness can be maintained only if the primary decision-making remains focused at location, even during routine operations. To provide offshore personnel with the necessary knowledge prior to specific operations, a range of preparatory engagements are held with the shore base	

	data including, if applicable, the location of any onshore data monitoring or data storage facilities; (4) The qualifications of the onshore personnel monitoring the data; (5) Your procedures for, and methods of, communication between rig personnel and the onshore monitoring personnel; and (6) Actions to be taken if you lose any real-time monitoring capabilities or communications between rig and onshore personnel, and a protocol for how you will respond to any significant and/or prolonged interruption of monitoring or onshore-offshore communications, including your protocol for notifying BSEE of any significant and/or prolonged interruptions.	engineering and operations support teams or through on-site engineering assistance. In these engagements, the key risks and critical steps are discussed to prepare the offshore team for the upcoming operations, including discussion of potential risks and appropriate responses. As operational issues arise, support is provided by shore-based organizations, leveraging real-time information, but authority remains in the field. It is for these reasons that it is strongly recommended the BSEE leave key operational decision-making in the hands of the Operators and focus regulations on ensuring the associated risks are addressed.	
§250.730(a)(2)	(2) Those provisions of the following industry standards (all incorporated by reference in § 250.198) that apply to BOP systems: (i) ANSI/API Spec. 6A; (ii) ANSI/API Spec. 16A; (iii) ANSI/API Spec. 16C; (iv) API Spec. 16D; and (v) ANSI/API Spec. 17D.	BSEE needs to provide guidelines on the intended objective of referencing these standards. Relevant sections of the required references are incorporated through requirement to comply with API 53.	Delete
§250.730(d)	(d) If you plan to use a BOP stack manufactured after the effective date of this regulation, you must	Delete as Quality System requirements are incorporated through API 53.	Delete or replace with: d) If you plan to use a BOP stack manufactured after the effective

	use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17011.	Reference in 250.730 is incorrect and should reference ISO 17021. BSEE has failed to distinguish between the activities of Accreditation Bodies (like COS) which accredit Audit Service Providers and the activities of the API Quality Registrar which serves as an Audit Service Provider (a.k.a. conformity assessment body) in conducting audits of quality management systems to API Spec Q1. The application of ISO 17011 in parts 250.1900, 250.1903, 250.1904, and 250.1922 appears to be correct. However, ISO 17011 **forbids** an accreditation body from offering or providing any services that affects its impartiality, such as those conformity assessment services that conformance assessment bodies perform. As an API QR is a	date of this regulation, you must use one manufactured pursuant to an API Spec. Q1 (as incorporated by reference in § 250.198) quality management system. Such quality management system must be certified by an entity that meets the requirements of ISO 17021.

		conformity assessment body (i.e. they actually perform audits of quality management systems) they cannot be accredited to ISO 17011. API QRs are currently accredited to ISO 17021. This standard is for "bodies providing audit and certification on management systems" this standard should be referenced instead of ISO 17011.	
§ 250.731(f)	(f) Certification stating that the MIA Report required in § 250.732(d) has been submitted within the past 12 months for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility.	Recommend deleting 250.731(f) as the rule is circular in logic as BSEE already has the report (i.e. requirement to certify the certification). Note: Industry is recommending the MIA Report requirement (§ 250.732(d)) be deleted as it is redundant to the per well certification required in § 250.731(c)(2) that the BOP was designed, tested, and maintained to perform under the maximum expected well conditions.	Delete

§250.732(a)	(a) BSEE will maintain a list of BSEE approved verification organizations (BAVOs) on its public website that you must use to satisfy any provision in this subpart that requires a BAVO certification, verification, report, or review. You must comply with all requirements in this subpart for BAVO certification, verification, or reporting no later than 1 year from the date BSEE publishes a list of BAVOs. (1) Until such time as you use a BAVO to perform the actions that this subpart requires to be performed by a BAVO, but not after 1 year from the date BSEE publishes a list of BAVOs, you must use an independent third-party meeting the criteria specified in paragraph (a)(2) of this section to prepare certifications, verifications, and reports as required by §§ 250.731(c) and (d), 250.732 (b) and (c), 250.734(b)(1), 250.738(b)(4), and 250.739(b). (2) The independent third-party must be a technical classification society, or a licensed professional engineering firm, or a registered professional engineer capable of providing the certifications, verifications, and reports required under paragraph (a)(1) of this section.	Unclear what value (if any) is achieved by the addition of the BAVO requirements in the rule. Before the rule, it was already very clear that the lease holder is responsible for what happens on the lease and is responsible for SMEs and Third Parties to oversee the contractor's work and documentation. The addition of the significant bureaucracy associated with the implementation of BAVOs will result in less clarity regarding responsibility (lease holder vs. BAVO vs. BSEE that approves the BAVO). Most of the requirements of BAVOs are already performed by third party certifying agencies and accepted by BSEE for ongoing operations.	Delete

	(3) For an organization to become a BAVO, it must submit the following information to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval: (i) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment; (ii) Technical capabilities; (iii) Size and type of organization; (iv) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment; (v) Ability to perform the verification functions for projects considering current commitments; (vi) Previous experience with BSEE requirements and procedures; and (vii) Any additional information that may be relevant to BSEE's review.		
§250.732 (c)	(c) For wells in an HPHT environment, as defined by § 250.807(b), you must submit verification by a BAVO that the verification organization conducted a comprehensive review of the BOP system and related equipment you propose to use. You	Delete this section as it is redundant to the per well certification required in § 250.731(c) that the BOP was designed, tested, and maintained to perform under the maximum expected well conditions. As	Delete

	must provide the BAVO access to any facility associated with the BOP system or related equipment during the review process. You must submit the verifications required by this paragraph (c) to the appropriate District Manager and Regional Supervisor before you begin any operations in an HPHT environment with the proposed equipment. You must submit: (1) Verification that the verification organization conducted a detailed review of the design package to ensure that all critical components and systems meet recognized engineering practices, (2) Verification that the designs of individual components and the overall system have been proven in a testing process that demonstrates the performance and reliability of the equipment in a manner that is repeatable and reproducible including: (i) Identification of all reasonable potential modes of failure; and (ii) Evaluation of the design verification tests. The design verification tests must assess the equipment for the identified potential modes of failure. (3) Verification that the BOP	outlined, requirement for a BAVO as opposed to the third party certification organizations currently accepted by BSEE adds an undue burden on industry and reduces transparency.	

	equipment will perform as designed in the temperature, pressure, and environment that will be encountered, and (4) Verification that the fabrication, manufacture, and assembly of individual components and the overall system uses recognized engineering practices and quality control and assurance mechanisms. For the quality control and assurance mechanisms, complete material and quality controls over all contractors, subcontractors, distributors, and suppliers at every stage in the fabrication, manufacture, and assembly process.		
§250.732 (d)	(d) Once every 12 months, you must submit a Mechanical Integrity Assessment Report for a subsea BOP, a BOP being used in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility. This report must be completed by a BAVO. You must submit this report to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, VA 20166. This report must include: (1) A determination that the BOP stack and system meets or exceeds all BSEE regulatory requirements,	Most of the MIA report is redundant since much of the referenced information is required to be submitted with each APD. It would be much more efficient for BSEE and industry to not require a separate MIA report, but rather, BSEE should include all necessary information referenced in 732(d) in the APD requirements.	Delete

	industry standards incorporated into this subpart, and recognized engineering practices. (2) Verification that complete documentation of the equipment's service life exists that demonstrates that the BOP stack has not been compromised or damaged during previous service. (3) A description of all inspection, repair and maintenance records reviewed, and verification that all repairs, replacement parts, and maintenance meet regulatory requirements, recognized engineering practices, and OEM specifications. (4) A description of records reviewed related to any modifications to the equipment and verification that any such changes do not adversely affect the equipment's capability to perform as designed or invalidate test results. (5) A description of the Safety and Environmental Management Systems (SEMS) plans reviewed related to assurance of quality and mechanical integrity of critical equipment and verification that the plans are comprehensive and fully implemented. (6) Verification that the qualification and training of inspection, repair, and		

	maintenance personnel for the BOP practices and any applicable OEM requirements. (7) A description of all records reviewed covering OEM safety alerts, all failure reports, and verification that any design or maintenance issues have been completely identified and corrected. (8) A comprehensive assessment of the overall system and verification that all components (including mechanical, hydraulic, electrical, and software) are compatible. (9) Verification that documentation exists concerning the traceability of the fabrication, repair, and maintenance of all critical components. (10) Verification of use of a formal maintenance tracking system to ensure that corrective maintenance and scheduled maintenance is implemented in a timely manner. (11) Identification of gaps or deficiencies related to inspection and maintenance procedures and documentation, documentation of any deferred maintenance, and verification of the completion of corrective action plans. (12) Verification that any inspection, maintenance, or repair work meets the manufacturer's design and		

	material specifications. (13) Verification of written procedures for operating the BOP stack and Lower Marine Riser Package (LMRP) (including proper techniques to prevent accidental disconnection of these components) and minimum knowledge requirements for personnel authorized to operate and maintain BOP components. (14) Recommendations, if any, for how to improve the fabrication, installation, operation, maintenance, inspection, and repair of the equipment.		
§250.734 (b)	(b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations, you must: (1) Submit a revised permit with a verification report from a BAVO documenting the repairs and that the BOP is fit for service; (2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with § 250.737(d)(4), including deadman. If repairs take longer than 30 days, once the BOP is on deck, you must test in accordance with the requirements of § 250.737; and (3) Receive approval from the District Manager.	Remove requirement for BAVO as outlined in response on §250.732(a). Additional deadman test is not supported by API 53. There is a low probability but very high consequence involved with each subsea deadman test that requires killing power and control fluid to the pods, industry feels there is a unwarranted safety and environmental risk to personnel, equipment, and assets.	Remove 250.734(b)or replace with: (b) If operations are suspended to make repairs to any part of the subsea BOP system, you must stop operations at a safe downhole location. Before resuming operations, you must: (1) Submit a revised permit with a verification report from an independent third party documenting the repairs and that the BOP is fit for service; (2) Upon relatch of the BOP, perform an initial subsea BOP test in accordance with § 250.737(d)(4). Deadman test required on surface prior to redeployment and only required subsea if any repairs were made to the deadman circuit; and

			(3) Receive approval from the District Manager.
§250.737 (d)(5)(ii)	**What are the BOP system testing requirements?** Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet the following testing requirements: (d) Additional test requirements. You must meet the following additional BOP testing requirements: You must (5) Alternate testing pods between control stations. (ii) Remote panels where all BOP functions are not included (e.g., life boat panels) must be function-tested upon the initial BOP tests and monthly thereafter.	Industry opposes 737(d)(5)(ii) because it is impractical, unnecessary and punitive. This requirement will result in excessive equipment wear and encourage equipment owners to remove optional remote pods (e.g., at life boats and on the bridge) that could negatively influence risk. Recommend that function testing be dictated by API 53.	Delete
Provisions to Revise			
§ 250.198 (h)(51)	(51) API Recommended Practice 2RD, Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs), First Edition, June 1998; Reaffirmed May 2006, including Errata June 2009, incorporated by reference at §§ 250.292, 250.733,	The second edition of 2RD has been published and supersedes RP 2RD First Edition. Improper reference to API RP 2RD in surface BOP requirement section (250.733).	51) API Standard 2RD, Dynamic Risers for Floating Production Systems, Second Edition, September 2013, incorporated by reference at §§ 250.292,
§ 250.198 (h)(63)	(63) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012, incorporated by reference at §§ 250.730, 250.735, 250.737, and 250.739;	Current edition but Addendum 1 issued July 2016; required adoption needed to prevent conflicts with 16C.	(63) API Standard 53, Blowout Prevention Equipment Systems for Drilling Wells, Fourth Edition, November 2012, Addendum 1, July 2016 incorporated by reference at §§ 250.730, 250.735, 250.737,

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§ 250.198 (h)(68)	(68) ANSI/API Specification Q1, Specification for Quality Programs for the Petroleum, Petrochemical and Natural Gas Industry, Eighth Edition, December 2007, incorporated by reference at §§ 250.730 and 250.806;	API Q1 9th ed. active; current basis for licensing/certification/ Monogram audits	(68) ANSI/API Specification Q1, Specification for Quality Management System Requirements for Manufacturing Organizations for the Petroleum and Natural Gas Industry, Ninth Edition, Includes Errata (February 2014), Errata 2 (March 2014), Addendum 1 (June 2016) incorporated by reference at §250.806
§ 250.198 (h)(89)	(89) ANSI/API Specification 11D1, Packers and Bridge Plugs, Second Edition, July 2009, incorporated by reference at §§ 250.518, 250.619, and 250.1703;	API Spec 11D1 3rd ed. was published April 2015, Current basis for product manufacture. Includes HPHT annex.	(89) ANSI/API Specification 11D1, Packers and Bridge Plugs, Third Edition, April 2015, incorporated by reference at §§ 250.518, 250.619, and 250.1703;
§250.413 (g)	(g) A single plot containing curves for estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, planned safe drilling margin, and casing setting depths in true vertical measurements.	Revert to pre-WCR text – deleting "planned safe drilling margin." Planned mud weight and expected fracture gradient will provide all relevant information in regards to drilling margin.	(g) A single plot containing estimated pore pressures, formation fracture gradients, proposed drilling fluid weights, and casing setting depths in true vertical measurements.
§250.414(c)(1)	(1) Your safe drilling margin must also include use of equivalent downhole mud weight that is: (i) greater than the estimated pore pressure, and (ii) except as provided in paragraph (2), a minimum of 0.5 pound per gallon below the lower of the casing shoe pressure integrity test or the lowest estimated fracture gradient.	Revert to pre-WCR text or adopt regulatory text (minus 0.5 ppg margin) proposed by industry at review with OMB in response to WCR.	(1) Your safe drilling margin must meet the following conditions: (i) equivalent downhole mud weight must be greater than estimated pore pressure; (ii) except as provided in paragraph (2) the margin between equivalent downhole mud weight and the lesser of the casing shoe pressure integrity test or the lowest fracture gradient must be: (i) 0.3 ppg; (ii) 2.5% of fracture gradient; or (iii)

			200 psi below the limiting formation integrity in the hole section as defined above.
§250.414(c)(3)	(3) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set well behavior observations.		(3) When determining the pore pressure and lowest estimated fracture gradient for a specific interval, you must consider related off-set and or analogous well behavior observations.
§250.420(a)(6)	(6) Provide adequate centralization to ensure proper cementation; and	Inconsistency from district to district on how this requirement is currently implemented. It's unclear why BSEE does not reference the currently incorporated API 65-2 to explain "adequate centralization" and "proper cementation." Operators design cement programs and required centralization based on well trajectory, mud weight, spacer volume, offset experience, modeling results, job objectives, and numerous other requirements. These factors are weighed in addition to the risk of adding potential obstructions in the well. These factors are taken into account by every operator and evaluated as outlined in API 65-2 to determine "adequate centralization" for their well	(6) Provide adequate centralization to meet cement job objectives consistent with the guidelines of API 65-2

		application. This provision as currently written is subjective and does not provide technical well control safety data in the industry to standardize and prescribe what "adequate centralization" requirements need to be.	
§250.421(f)	(f) Liners - Casing requirements: If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing. A subsea well casing string whose top is above the mudline and that has been cemented back to the mudline will not be considered a liner. Cementing requirements: Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing. If you have a liner lap and are unable to cement 500 feet above the previous shoe, as provided by (d) and (e), you must submit and receive approval from the District Manager	Well specific details may prevent placing 500' of cement or it may be impractical due to "annular pressure" concerns. Cementing analysis should incorporate evaluation of annular barriers including packers, seal assemblies, etc.	(f) If you use a liner as surface casing, you must set the top of the liner at least 200 feet above the previous casing/liner shoe. If you use a liner as an intermediate string below a surface string or production casing below an intermediate string, you must set the top of the liner at least 100 feet above the previous casing shoe. You may not use a liner as conductor casing. A casing string whose top is above the mudline and that has been cement back to the mudline will not be considered a liner. Cementing requirements: Same as cementing requirements for specific casing types. For example, a liner used as intermediate casing must be cemented according to the cementing requirements for intermediate casing. If you have a liner lap and are unable to cement 500 feet above the previous shoe, as provided by (d) and (e), you must

	on a case-by-case basis.		submit well specific cementing objectives in the APD or APM for District Manager approval.
§250.428(c)	If you encounter the following situation: (c) Have indication of inadequate cement job (such as lost returns, no cement returns to mudline or expected height, cement channeling, or failure of equipment), Then you must… (1) Locate the top of cement by: (i) Running a temperature survey; (ii) Running a cement evaluation log; or (iii) Using a combination of these techniques. (2) Determine if your cement job is inadequate. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.	This requirement is not defined sufficiently which results in inconsistent application across districts and delays in operations. Ambiguity in the regulation, results in operators waiting on approval from the regulatory body to set liner top packers immediately after a cement job in some instances. Allowing the operator to make a real-time determination based on lift pressure / volumetrics would reduce risk by allowing additional mechanical barriers to be installed prior to cement transition (liner top packer, seal assembly, etc.). Further, if cement is planned to the TOL, there is potential risk of a stuck pipe incident while waiting on regulatory confirmation.	If you encounter the following situation: (c) Have indication of inadequate cement job (such as unplanned lost returns, no cement returns to mudline, cement channeling, or failure of equipment), Then you must… (1) Locate the top of cement by: (i) Lift pressure analysis and/or volumetrics; (ii) Running a temperature survey; (iii) Running a cement evaluation log; or (iv) Use radioactive tracer in cement and logged with LWD when TIH to drill out, (v) drill out and confirm integrity with a shoe test; or (vi) Using a combination of these techniques. (2) Determine if your cement job is inadequate based on pre-job objectives as outlined in API 65-2 evaluation for zonal isolation. If your cement job is determined to be inadequate, refer to paragraph (d) of this section. (3) If your cement job is determined to be adequate, report the results to the District Manager in your submitted WAR.
§250.428(d)	If you encounter the following situation: (d) Inadequate cement job,	Two Industry concerns are the need for PE sign-off and the	If you encounter the following situation: (d) Inadequate cement

	Then you must… Take remedial actions. The District Manager must review and approve all remedial actions before you may take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete. Any changes to the well program will require submittal of a certification by a professional engineer (PE) certifying that he or she reviewed and approved the proposed changes, and must meet any other requirements of the District Manager.	need to wait for approval from the District Manager for an operation that has already been thought out as part of the contingency plan for a cement job that is deemed inadequate in real-time. The request would be to have pre-approval for items such as liner-top squeezes that are time sensitive in nature. There is inconsistency amongst districts on how this is handled proactively.	job, Then you must… comply with §250.428(c) and locate top of cement. Where remedial actions are necessary, the District Manager must review and approve all remedial actions either through a previously approved contingency plan within the APD or remedial actions outlined in an RPD before you take them, unless immediate actions must be taken to ensure the safety of the crew or to prevent a well-control event. Advanced approval may be provided for time sensitive remedial operations within the APD. If you complete any immediate action to ensure the safety of the crew or to prevent a well-control event, submit a description of the action to the District Manager when that action is complete.
§250.462(b)	(b) You must have access to and the ability to deploy Source Control and Containment Equipment (SCCE) and all other necessary supporting and collocated equipment to regain control of the well. SCCE means the capping stack, cap-and-flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels, which have the collective purpose to control a spill source and stop the flow of fluids	Industry is supportive of the well containment analysis outlined in §250.462(a) and believes that well containment equipment requirements should be aligned with the well specific details. Specifically outlining the equipment requirements limits future technology development for source control equipment and places an undue burden on potential future drilling	(b) You must have access to and the ability to deploy Source Control and Containment Equipment (SCCE) and all other necessary supporting and collocated equipment to regain control of the well based on the requirements outlined in §250.462(a). SCCE means the capping stack, cap -and -flow system, containment dome, and/or other subsea and surface devices, equipment, and vessels which have

	into the environment or to contain fluids escaping into the environment. This SCCE, supporting equipment, and collocated equipment must include, but is not limited to, the following: (1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment including hydraulic power sources and hydrate control equipment; (3) Collocated equipment including dispersant injection equipment; (4) Riser systems; (5) Remotely operated vehicles (ROVs); (6) Capture vessels; (7) Support vessels; and (8) Storage facilities.	operations outside of the GoM.	the collective purpose to control a spill source and stop the flow of fluids into the environment or to contain fluids escaping into the environment. This SCCE, supporting equipment, and collocated equipment may include, but is not limited to, the following: (1) Subsea containment and capture equipment, including containment domes and capping stacks; (2) Subsea utility equipment, including hydraulic power, sources and hydrate control, and equipment; (3) Collocated equipment including dispersant injection equipment; (4) Riser systems; (5) Remotely operated vehicles (ROVs); (6) Capture vessels; (7) Support vessels; and (8) Storage facilities.
§250.462(e)(1)(ii)	(ii) Pressure test pressure containing critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by BSEE (if available) and a BSEE-approved verification organization	Regulations need to separate the difference between a capping stack and BOP which requires a BSEE-approved verification organization. Industry has successfully proven over six years of satisfactory testing globally and in the US where competent thirty parties have met the same standards as when BSEE is present.	ii) Pressure test pressure containing critical components on a bi-annual basis, but not later than 210 days from the last pressure test. All pressure testing must be witnessed by a competent third party. BSEE must be provided 72hr notification prior to testing.
§250.462 (e)(3)	(e) You must maintain, test, and	The agency did not	(e) You must maintain, test, and

	inspect the source control, containment, and collocated equipment identified in the following table according to these requirements: (3)Subsea utility equipment, Have all referenced containment equipment available for inspection at all times. Subsea utility equipment includes, but is not limited to: Hydraulic power sources, debris removal, and hydrate control equipment.	accept the recommendation that the word "uniquely" be added to the regulation in §250.462(e)(3),"…Have all equipment utilized uniquely for containment operations available for inspection at all times." The intent of adding "uniquely" was to reduce the burden of access to equipment retained or readily available in the GOM; e.g. debris removal equipment, coil tubing units, gas detection systems, vessels, Remote Operating Vessels	inspect the source control, containment, and collocated equipment identified in the following table according to these requirements: (3)Subsea utility equipment, Have all equipment utilized uniquely for containment operations that served no other services available for inspection at all times.
§ 250.462 (e)(4)	You must maintain, test, and inspect the source control, containment, and collocated equipment identified in the following table according to these requirements: Collocated equipment, Have equipment available for inspection at all times ..... Collocated equipment includes, but is not limited to, dispersant injection equipment and other subsea control equipment.	The agency also added the requirements around collocated equipment. The industry's interpretation of the term "collocated" is the SCCE stored at the sites designated by the operator in their Regional Containment Demonstration ("RCD") or Well Containment Plan ("WCP").	You must maintain, test, and inspect the source control, containment, and collocated equipment designated by the operator in the Regional Containment Demonstration (RCD) or Well Containment Plan (WCP) identified in the following table according to these requirements: Collocated equipment, Have equipment available for inspection at all times. Collocated equipment includes, but is not limited to, dispersant injection equipment and

			other subsea control equipment.
§ 250.712 (a)	(a) You must report the movement of all rig units on and off locations to the District Manager using Form BSEE–0144, Rig Movement Notification Report. Rig units include MODUs, platform rigs, snubbing units, wire-line units used for non-routine operations, and coiled tubing units. (1) The arrival of a rig unit on location; (2) The movement of a rig unit to another slot. For movements that will occur less than 24 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE–0144; or (3) The departure of a rig unit from the location.	Recommend revision of 30 CFR 250.712: BSEE is requiring operators to submit Rig Move Notifications Reports for short duration/short distance temporary unlatches or suspensions tree installation or weather. Industry original submittal for recommended wording outlined notification for arrival on location prior to the commencement of operations and departure of the rig from the location at the completion of operations.	(a)You must inform the District Manager of rig unit movements using Form BSEE-0144 (Rig Movement Notification Report) 24 hours before: (1) The arrival of a rig unit on location prior to commencing operations. (2) The movement of a rig unit to another slot. For movements that will occur less than 24 hours after initially moving onto location (e.g., coiled tubing and batch operations), you may include your anticipated movement schedule on Form BSEE–0144; or (3) The departure of a rig unit from the location at the completion of all well operations. Rig units include MODUs and platform rigs.
§250.730(a)	(a) You must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. The working pressure rating of each BOP component (excluding annular(s)) must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be taken at the mudline.	The meaning of "flowing conditions" is ambiguous. Recommendation to make the rule match the BSEE FAQ. BSEE Q: The BOP system (excluding casing shear) must be capable of closing and sealing the wellbore at all times, including under anticipated	(a) You must ensure that the BOP system and system components are designed, installed, maintained, inspected, tested, and used properly to ensure well control. The working pressure rating of each BOP component (excluding annular(s)) must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be

	The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Your BOP system (excluding casing shear) must be capable of closing and sealing the wellbore at all times, including under anticipated flowing conditions for the specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that the BOP system may encounter. Your BOP system must meet the following requirements: (1) The BOP requirements of API Standard 53 (incorporated by reference in § 250.198) and the requirements of §§ 250.733 through 250.739. If there is a conflict between API Standard 53, and the requirements of this subpart, you must follow the requirements of this subpart. (2) Those provisions of the following industry standards (all incorporated by reference in § 250.198) that apply to BOP systems: (i) ANSI/API Spec. 6A; (ii) ANSI/API Spec. 16A;	flowing conditions for the specific well conditions, without losing ram closure time and sealing integrity. Industry's interpretation of anticipated flowing conditions is shutting in on a "kick". Is this interpretation correct? BSEE A: Yes, the BOP system must be designed to shut-in a well that is flowing due to a kick. Also, API Standard 53 references the specifications by manufacture date instead of using a dated reference. Using a dated reference as the well control rule can prevent the industry from using updated editions to a specification, or a previous edition that was in effect when the equipment was manufactured. Note: API RP 59 currently utilized to determine kick parameters for well construction purposes.	taken at the mudline. The BOP system includes the BOP stack, control system, and any other associated system(s) and equipment. The BOP system and individual components must be able to perform their expected functions and be compatible with each other. Your BOP system (excluding casing shear) must be capable of closing and sealing the wellbore in the event of flow due to a kick, including under anticipated flowing conditions for the specific well conditions, without losing ram closure time and sealing integrity due to the corrosiveness, volume, and abrasiveness of any fluids in the wellbore that the BOP system may encounter. Your BOP system must meet the following requirements: (1) The BOP requirements of API Standard 53 (incorporated by reference in § 250.198) and the requirements of §§ 250.733 through 250.739. If there is a conflict between API 53, and the requirements of this subpart, you must follow the requirements of this subpart. (2) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be

	(iii) ANSI/API Spec. 16C; (iv) API Spec. 16D; and (v) ANSI/API Spec. 17D. (3) For surface and subsea BOPs, the pipe and variable bore rams installed in the BOP stack must be capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding tubing with exterior control lines and flat packs) in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system. (4) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will change your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.		capable of effectively closing and sealing on the tubular body of any drill pipe, workstring, and tubing (excluding tubing with exterior control lines and flat packs) in the hole under MASP, as defined for the operation, with the proposed regulator settings of the BOP control system. (3) The current set of approved schematic drawings must be available on the rig and at an onshore location. If you make any modifications to the BOP or control system that will change your BSEE-approved schematic drawings, you must suspend operations until you obtain approval from the District Manager.
§250.730(b)	(b) You must ensure that the design, fabrication, maintenance, and repair of your BOP system is in accordance with the requirements contained in this part, Original Equipment Manufacturers (OEM) recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or	It is unclear what is included with "any OEM training recommendations". Industry proposed text contains greater clarity and would be actionable. Separate from the WCR, industry is progressing a training program that may include accreditation for working or supervising BOP maintenance and repair.	(b) The training and qualification of repair and maintenance personnel must meet or exceed applicable OEM training requirements unless otherwise directed by BSEE.

	exceed any OEM training recommendations unless otherwise directed by BSEE.	This is aligned with requirements in .732(d)(6)	
§250.730(c)	(c) You must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A (all incorporated by reference in § 250.198), and: (1) You must provide a written notice of equipment failure to the Chief, Office of Offshore Regulatory Programs, and 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. (2) 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. You must also ensure that the results and any corrective action are documented. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the Chief, Office of Offshore Regulatory Programs and the manufacturer receive a copy of the analysis report. (3) If the equipment manufacturer notifies you that it has changed the design of the equipment that failed or if you have changed operating or	The RAPID-S53 database is owned and operated by the IADC-coordinated IADC/IOGP BOP Reliability Joint Industry Project (JIP) and has been set up to provide the Oil & Gas industry with a source of data that can be used to improve the Reliability and Performance of the Well Control Equipment covered by API 53. The database is currently used by the JIP participants to collect data on all events where WCE components fail to perform as designed and to provide WCE System Integrators and component Original Equipment Manufacturers (OEMs) with details of such events, in compliance with API 53. The database is also being used to assist Operators working in the USA to comply with the Equipment Failure Notification requirements of the Well Control Rule governing operations on federally-controlled oil and gas leases. The OEM and Operator members have access to their	(c) You must follow the failure reporting procedures contained in API Standard 53 (incorporated by reference in § 250.198), and: (1) You must provide a written notice of equipment failure data to the Chief, Office of Offshore Regulatory Programs via the www.SafeOCS.gov website, with a copy 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 and resulted in suspension of operations. (2) You must ensure that an investigation and a failure analysis are in progress for any events that resulted in suspension of operations within 120 days of access to the equipment to determine the cause of the failure. You must also ensure that the results and any corrective action are documented. If the investigation and analysis are performed by an entity other than

	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. (4) You must send the reports required in this paragraph to: Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; 45600 Woodland Road, Sterling, VA 20166.	specific data which allows them to fulfill their regulatory reporting requirements.	the manufacturer, you must ensure that the www.SafeOCS.gov website and the manufacturer receive a copy of the analysis report. (3) 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. (4) You must send the reports required in this paragraph to: www.SafeOCS.gov
§ 250.731(c) and (d)	What information must I submit for BOP systems and system components? For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you have submitted this	Remove requirement for a BAVO. In proposing the BSEE Approved Verification Organizations (BAVOs), another exposure area is created where responsibility, accountability, and liability of BSEE needs to be clarified. The proposal includes BAVO certification in a range of areas such as BOP shear capabilities, BOP design and maintenance, BOP application in HPHT wells,	What information must I submit for BOP systems and system components? For any operation that requires the use of a BOP, you must include the information listed in this section with your applicable APD, APM, or other submittal. You are required to submit this information only once for each well, unless the information changes from what you provided in an earlier approved submission or you have moved off location from the well. After you

	information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes or you have moved off location from the well, you must submit updated information in your next submission. You must submit: (a) A complete description of the BOP system and system components, (1) Pressure ratings of BOP equipment; (2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures); (3) Rated capacities for liquid and gas for the fluid-gas separator system; (4) Control fluid volumes needed to close, seal, and open each component; (5) Control system pressure and regulator settings needed to achieve an effective seal of each ram BOP under MASP as defined for the operation; (6) Number and volume of accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles);	and capping stacks. Currently no BAVOs exist and BSEE is accepting certification from independent third party agencies that have been thoroughly evaluated by Operators. Industry does not believe that the BAVO process will enhance safety or reliability, but add an additional regulatory burden. In the event that BSEE seeks to further engage in these decisions on equipment certification via BAVOs, clarification is required on the associated responsibility, accountability and liability that would be assumed by BSEE in the event of any incidents that occur in connection with those actions. It is for these reasons that it is strongly recommended the BSEE leave validation of equipment certification in the hands of the Operators and focus regulations on ensuring the associated risks are addressed.	have submitted this information for a particular well, subsequent APMs or other submittals for the well should reference the approved submittal containing the information required by this section and confirm that the information remains accurate and that you have not moved off location from that well. If the information changes, or you have moved off location from the well, you must submit updated information in your next submission. You must submit: (a) A complete description of the BOP system and system components, (1) Pressure ratings of BOP equipment; (2) Proposed BOP test pressures (for subsea BOPs, include both surface and corresponding subsea pressures); (3) Rated capacities for liquid and gas for the fluid-gas separator system; (4) Control fluid volumes needed to close, seal, and open each component; (5) Control system pressure and regulator settings needed to close a ram BOP under MASP as defined for the operation; (6) Number and volume of

	(7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations); (8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes). (b) Schematic drawings, (1) The inside diameter of the BOP stack; (2) Number and type of preventers (including blade type for shear ram(s)); (3) All locking devices; (4) Size range for variable bore ram(s); (5) Size of fixed ram(s); (6) All control systems with all alarms and set points labeled, including pods; (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP); (8) Associated valves of the BOP system; (9) Control station locations; and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines down to the BOP. (c) Certification by a BSEE-approved verification organization (BAVO), Verification that: (1) Test data demonstrate the shear ram(s) will shear the drill pipe at the		accumulator bottles and bottle banks (for subsea BOP, include both surface and subsea bottles); (7) Accumulator pre-charge calculations (for subsea BOP, include both surface and subsea calculations); (8) All locking devices; and (9) Control fluid volume calculations for the accumulator system (for a subsea BOP system, include both the surface and subsea volumes). (b) Schematic drawings, (1) The inside diameter of the BOP stack; (2) Number and type of preventers (including blade type for shear ram(s)); (3) All locking devices; (4) Size range for variable bore ram(s); (5) Size of fixed ram(s); (6) All control systems with all alarms and set points labeled, including pods; (7) Location and size of choke and kill lines (and gas bleed line(s) for subsea BOP); (8) Associated valves of the BOP system; (9) Control station locations; and (10) A cross-section of the riser for a subsea BOP system showing number, size, and labeling of all control, supply, choke, and kill lines

	water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well; and (3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system. (d) Additional certification by a BAVO, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807, or a surface BOP on a floating facility, Verification that: (1) The BOP stack is designed and suitable for the specific equipment on the rig and for the specific well design; (2) The BOP stack has not been compromised or damaged from previous service; and (3) The BOP stack will operate in the conditions in which it will be used.		down to the BOP. (c) Certification by an independent third party that: (1) Test data demonstrate the shear ram(s) will shear the drill pipe at the water depth as required in § 250.732; (2) The BOP was designed, tested, and maintained to perform under the maximum environmental and operational conditions anticipated to occur at the well; and (3) The accumulator system has sufficient fluid to operate the BOP system without assistance from the charging system.
§250.732(b)	(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BAVO and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.	Replace BAVO with independent third party certifying agency as outlined above.	(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by an independent third-party professional engineer or professional engineering firm and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.

§250.732(b)(1)(iv)	You must submit verification and documentation related to: (iv) Ensures testing was performed on the outermost edges of the shearing blades of the shear ram positioning mechanism as required in § 250.734(a)(16);	250.734(a)(16)(i) has the following: (16) Use a BOP system that has the following mechanisms and capabilities; (i) A mechanism coupled with each shear ram to position the entire pipe, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism no later than May 1, 2023; Therefore, the requirement for the BAVO to provide verification as detailed in 732(b)(1)(iv) must be required beginning in May, 2023 since the equipment is not required to have centering capability until then. Also, the requirement should be as stated above from 732: ensure that shearing will occur. It should not prescribe if the actual shearing occurs on the outermost edge, or, if the centering mechanism brings the pipe to a position that shearing	You must submit verification and documentation related to: (iv) After May 1, 2023, ensures testing was successfully performed with a shear assembly that meets the requirements of § 250.734(a)(16).

		occurs.	
§250.732(b)(2)	(2) Pressure integrity testing, and (i) Shows that testing is conducted immediately after the tests; (ii) Demonstrates that the equipment will seal at the rated working pressures (RWP) of the BOP for 30 minutes; and (iii) Includes all relevant test results.	Requiring a pressure test hold time of 30 minutes invalidates years of test data and proven industry experience that would be cumbersome to duplicate and cause unnecessary delay. It is unclear what problem is being addressed and how this would have any impact on risk reduction.	(2) Pressure integrity testing, and (i) Shows that testing is conducted immediately after the shearing tests; (ii) Demonstrates that the equipment will seal at the rated working pressures (RWP) of the BOP for 3 minutes; and (iii) Includes all relevant test results.
§250.733 (a)(1)	(1) The blind shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing provided that the capability to shear tubing with exterior control lines is not required prior to April 30, 2018, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. If your blind shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device must be available on the rig floor during operations that require their use.	Intent of industry revision is to recognize BSEE's desire to have verification that the tool works. This would be in place of BAVO. From BSEE Q&A Question: Will we need verification from a 3rd party, if an alternative cutting device is used to cut an electric-, wire-, or slick-line under MASP (Maximum Anticipated Surface Pressure)? Answer: The requirement for verification according to 250.732(b)(1)(i) of the capacity to shear any electric-, wire-, or slick-line to be used in the hole, takes effect on April 30, 2018. From that point: until one year after the date BSEE publishes a list of BAVOs, an independent	(1) The blind-shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies that include heavy-weight pipe or collars), workstring, tubing, and any electric-, wire-, and slick-line that is in the hole and sealing the wellbore after shearing. If your blind-shear rams are unable to cut any electric-, wire-, or slick-line under MASP as defined for the operation and seal the wellbore, you must use an alternative cutting device capable of shearing the lines before closing the BOP. This device function must be proof tested prior to commissioning on the rig and copies of the testing available upon request. It must be available on the rig floor during operations that require their use.

		third-party must verify that the alternative cutting device can cut the line to be used in the hole; beginning one year after BSEE publishes a list of BAVOs, a BAVO must verify that the alternative cutting device can cut the lines to be used in the hole. This alternative cutting device does not need to be certified under MASP	
§250.734 (a)(1)(ii)	(ii) Both shear rams must be capable of shearing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing provided that the capability to shear tubing with exterior control lines is not required prior to April 30, 2018, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole no later than April 30, 2018; under MASP. At least one shear ram must be capable of sealing the wellbore after shearing under MASP conditions as defined for the operation. Any non-sealing shear ram(s) must be installed below a sealing shear ram(s).	Requirement for both shear rams to cut wireline is inconsistent with API 53. Some rigs may have to remove casing shear rams or add a third ram. BSEE does not recognize that annular BOP will close and seal on wireline - OEMs confirm this capability. However, wireline disconnect capabilities provide a secondary means of removing the WL from across the BOP in a stuck logging tool scenario. In addition, requirement altered to be consistent with API 53 which requires the combination of the shear rams to be able to shear and seal the wellbore. This is critical for operations with known spaceouts (casing landed with landing string or SSTT) where spaceout or	(ii) The combination of the installed shear rams must be capable of shearing and sealing at any point along the tubular body of any drill pipe (excluding tool joints, bottom-hole tools, and bottom hole assemblies such as heavy-weight pipe or collars), workstring, tubing, appropriate area for the liner or casing landing string, shear sub on subsea test tree, and any electric-, wire-, slick-line in the hole no later than April 28, 2018; under MASP.

		mechanical properties may restrict ability for both rams to shear equipment. Note that in landed position tool joint location is known and designed to allow closure of at least one shear ram.	
§250.734 (a)(3)	The accumulator capacity must: (i) Operate each required shear ram, ram locks, one pipe ram, and disconnect the LMRP. (ii) Have the capability of delivering fluid to each ROV function i.e., flying leads. (iii) No later than April 29, 2021, have bottles for the autoshear, and deadman that are dedicated to, but may be shared between, those functions. (iv) Perform under MASP conditions as defined for the operation.	ROV flying lead requirement is incremental to recommendations established by Industry experts via documents such as API Standard 53. These requirements above and beyond the API Standard 53 introduce additional complexity and risks to BOPs without BSEE providing adequate justification or support for the changes. It is imperative that BSEE provide a specifically defined benefit objective for each proposed deviation and provide Industry the opportunity for further engagement to avoid inadvertently increasing operational risk. To avoid unintended complications, BSEE should avoid requirements beyond API Standard 53 or complete a comprehensive analysis of the specific net risk, cost and operational impacts as a result of each proposed change.	The accumulator capacity must be designed to: (i) Supply the highest useable fluid requirement to (1) close shear ram(s) as required to secure the well with autoshear or deadman systems using API 16D Rapid Discharge, Method C calculation methods, or (2) operate all ROV secondary critical functions to close required shear ram(s), close a pipe ram, energize ram locks, and unlatch the LMRP disconnect using API 16D, Method B calculation. (ii) Have the capability to perform ROV functions within required times outlined in API 53 Fourth Edition with ROV or flying leads. (iii) No later than April 29, 2021, have bottles for the autoshear, and deadman (which can be shared between those two systems) to secure the wellbore, but may also be utilized to perform the ROV secondary critical functions or acoustic functions, if applicable to secure the well. (iv) Perform under MASP conditions

		Recommendation to modify language to ensure ROV functions meet the closing time requirements outlined in API 53 either through a high capacity ROV pump or flying leads from subsea accumulation. Regulation needs to be revised to permit sharing of accumulator bottles between deadman / autoshear and ROV functions if flying lead is utilized. The original requirement was unclear regarding whether it is a test requirement, or, a design requirement. We believe it is a design requirement, however, it is missing many parameters needed to design the accumulator system. It is suggested to use the API design specification contained in API 16D as it has been vetted and proven sound in operation.	as defined for the operation.
§250.734 (a)(4)	(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or before conducting operations if the well is already deepened beyond the surface casing point. The District Manager	It is unclear of the intent in what BSEE is attempting to achieve by adding open functionality to the critical function list. Opening of a ram is not a critical function. Industry recommends changing the language to reflect API 53 as	(a) When you drill or conduct operations with a subsea BOP system, you must install the BOP system before drilling to deepen the well below the surface casing or before conducting operations if the well is already deepened beyond the surface casing point. The

	may require you to install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements. When operating with a subsea BOP system, you must: (4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability; The ROV must be capable of opening and closing each shear ram, ram locks, one pipe ram, and LMRP disconnect under MASP conditions as defined for the operation. The ROV panels on the BOP and LMRP must be compliant with API RP 17H (as incorporated by reference in §250.198).	written and implemented. Addendum to API 53 should also be included in any updates assigned to documents incorporated by reference into the rule (API 53 specifically). Outdated edition of API 17H is referenced. BSEE claims that the older edition was incorporated by reference because the latest edition was being revised at the time of writing the WCR. 17H 2nd edition was published in June 2013 and errata added in January 2014. The version sited within the WCR is First Edition, July 2004. Recommended text utilizes API 53 to incorporate API 17H, and any future changes, properly.	District Manager may require you to install a subsea BOP system before drilling or conducting operations below the conductor casing if proposed casing setting depths or local geology indicate the need. The following table outlines your requirements. When operating with a subsea BOP system, you must: (4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability; The ROV must be capable of performing critical functions as defined in API Standard 53 (as incorporated by reference in § 250.198).
§250.734 (a)(6)	(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs: (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the	Industry recommends modifying (iv) because there will be other sequences that better address well control and disconnect risks present during certain operations. Factors include neutral point of the string, shearability, string position, water depth, weather windows,	(6) Provide autoshear, deadman, and EDS systems for dynamically positioned rigs; provide autoshear and deadman systems for moored rigs; (i) Autoshear system means a safety system that is designed to automatically shut-in the wellbore in the event of a disconnect of the

	LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) Each emergency function must have an option to close at a minimum, two shear rams in sequence and be capable of performing its expected shearing and sealing action under MASP conditions as defined for the operation. (v) Your sequencing must allow a sufficient delay for closing the upper shear ram after beginning closure of the lower shear ram to provide for maximum sealing efficiency. (vi) The control system for the emergency functions must be a fail-safe design once activated.	ram configuration, redundancies, well status (# of existing barriers), etc. Delete (v) and (vi) because there may be other sequences that better address well control risks present during a specific operation. This is too prescriptive, the object is to secure the well, which ever sequence of well control preventer action is best suited to reduce overall risks to people, the environment, and the well should be used. Alternately, if the text in the rule is not changed, it is proposed that an interpretation is documented that "A failsafe design in this paragraph means that the DMAS is designed to operate without intervention to leave the well safe in the case of a simultaneous loss of power and control to both primary pods, or an inadvertent LMRP disconnect."	LMRP. This is considered a rapid discharge system. (ii) Deadman system means a safety system that is designed to automatically shut-in the wellbore in the event of a simultaneous absence of hydraulic supply and signal transmission capacity in both subsea control pods. This is considered a rapid discharge system. (iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to shut-in the wellbore and disconnect the LMRP in the event of an emergency situation. This is considered a rapid discharge system. (iv) Each emergency function must have an option to close two shear rams in sequence and be capable of performing its expected shearing and sealing action under MASP conditions as defined for the operation.

§250.734 (a)(16)	(16) Use a BOP system that has the following mechanisms and capabilities; (i) A mechanism coupled with each shear ram to position the entire pipe, completely within the area of the shearing blade and ensure shearing will occur any time the shear rams are activated. This mechanism cannot be another ram BOP or annular preventer, but you may use those during a planned shear. You must install this mechanism no later than May 1, 2023; (ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed; (iii) If your control pods contain a subsea electronic module with batteries,a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.	The rule as written is prescriptive and limits ability for future technology developments. The rule should state the function requirements and allow technical flexibility as to how the ram is designed and functions to achieve the objective. Centering Shear Mechanism is not always necessary and the rule has ambiguous requirements (i.e. compression.)	(16) Use a BOP system that has the following capabilities; (i) ensure shearing will occur when the shear rams are activated. (ii) If your control pods contain a subsea electronic module with batteries, a mechanism for personnel on the rig to monitor the state of charge of the subsea electronic module batteries in the BOP control pods.
§250.735 (a)	(a) An accumulator system (as specified in API Standard 53) that provides the volume of fluid capacity (as specified in API Standard 53, Annex C) necessary to close and hold closed all BOP components against MASP. The system must operate under MASP conditions as defined for the operation. You must be able to operate the BOP functions as defined	Industry SMEs including OEM, Operator, Contractor, 3rd parties and BSEE collaborated to produce API Standard 53 design and accumulator sizing requirements. The industry has reviewed and revised these calculations to reflect how gasses behave at these temperatures and pressures.	(a) An accumulator system that provides the volume of fluid capacity (as specified in API Standard 53, Fourth Edition Annex C) necessary to operate required components against expected conditions. You must be able to operate the BOP functions as defined in API Standard 53, Fourth Edition, without assistance from a

	in API Standard 53, Fourth Edition, without assistance from a charging system, and still have a minimum pressure of 200 psi remaining on the bottles above the pre-charge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;	The BSEE proposed requirement contradicts the requirements of API Standard 53. The proposed BSEE rule to "close all BOP functions" and hold closed against MASP may penalize rigs that have more BOP equipment than the minimum BOP specified by BSEE in proposed rule 250.734 (a)(1) which is one annular and four rams. For rigs with two annulars and six or seven rams, the impact would be considerable. So, for those rigs which have more redundancy in equipment but fail to meet this proposed BSEE surface volume rule, theoretically they could strip equipment off the bigger, more redundant stacks to meet minimum BSEE BOP equipment and surface accumulator requirements. The volume requirement should be in relation to the BSEE minimum BOP equipment requirements. API Standard 53 and API Specification 16D are the guidelines that rigs are designed and built by to work worldwide. Thus, if BSEE changes the accumulator requirements, it would impact the available rigs	charging system, and still have a minimum pressure of 200 psi remaining on the bottles above the pre-charge pressure. If you supply the accumulator regulators by rig air and do not have a secondary source of pneumatic supply, you must equip the regulators with manual overrides or other devices to ensure capability of hydraulic operations if rig air is lost;

		to conduct operations in OCS waters. Revised language around operating all BOP components against MASP as annulars may be rated to a lower RWP than the BOP.	
§250.737 (a)(2)	(2) Before 14 days have elapsed since your last BOP pressure test, or 30 days since your last blind shear ram BOP pressure test. You must begin to test your BOP system before midnight on the 14th day (or 30th day for your blind shear rams) following the conclusion of the previous test;	Pressure tests create additional risk due to accelerated wear relative to function tests. Change requirement from 14 days for pressure tests to 21 days. Effectively, select Alternative 2 as listed in the Final WCR, page 25991 of the Federal Register to be consistent with API 53. Note: the District Manager already has the ability to alter the frequency as detailed in 737(a) (4): The District Manager may require more frequent testing if conditions or your BOP performance warrant.	(2) You must test your BOP system according to the frequency specified in API 53 Fourth Edition, Table 10;
§250.737 (b)(2)	(2) High-pressure test for blind shear ram-type BOPs, ram-type BOPs, the choke manifold, outside of all choke and kill side outlet valves (and annular gas bleed valves for subsea BOP), inside of all choke and kill side outlet valves below uppermost ram, and other BOP components. The high-pressure test must equal the RWP of the equipment or be 500 psi greater than your calculated MASP, as	Suggested clarification language is proposed to align the WCR with API 53.	(2) The BSR will be tested to the highest well MASP + 500 psi. on latch up, or, to the highest well MASP + 500 psi test before the highest MASP hole section is drilled. Before the BSR is tested to MASP plus 500 psi for the next hole section, the District Manager must have approved those test pressures in the APD. For side outlet valves, the following test pressures will be

	defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MASP plus 500 psi, the District Manager must have approved those test pressures in your APD.		followed: a. The Inner and Outer side outlet valves will be tested to MASP + 500 psi on initial latch up or subsequent test prior to the highest MASP hole section. b. For pressure testing of the BOP, the side outlets below the uppermost pipe ram will be tested to pipe ram pressure. The side outlets above the uppermost pipe rams will be tested to Annular test pressure. The non-wellbore side of the side outlet valves will be tested to pipe ram test pressure (MASP + 500 psi). c. For subsequent BSR test after initial latch up, the inner and outer side outlets below the uppermost BSRs will be tested to casing test pressure.
§250.737 (d)(3)	What are the BOP system testing requirements? Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet the following testing requirements: (d) Additional test requirements. You must (3) Stump test a subsea BOP system before installation: (i) You must use water to conduct this test. You may use drilling/completion	Suggested clarification language is proposed to align the WCR with API 53.	What are the BOP system testing requirements? Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet API 53 Fourth Edition testing requirements. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) Contact the District Manager at

	/workover fluids to conduct subsequent tests of a subsea BOP system. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) Contact the District Manager at least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests. (iv) You must test and verify closure of all ROV intervention functions on your subsea BOP stack during the stump test.		least 72 hours prior to beginning the stump test to allow BSEE representative(s) to witness testing. If BSEE representative(s) are unable to witness testing, you must provide the test results to the appropriate District Manager within 72 hours after completion of the tests. (iv) You must test and verify closure of critical ROV intervention functions on your subsea BOP stack during the stump test. Or (iv) You must test ROV intervention functions on your subsea BOP stack during the stump test in conformance with API 53 Fourth Edition, table 6.
§250.737 (d)(4)	You must…(4) Perform an initial subsea BOP test. Additional requirements… (i) You must perform the initial subsea BOP test on the seafloor within 30 days of the stump test. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) You must pressure test well-control rams according to (b) and (c) of this section. (iv) You must notify the District Manager at least 72 hours prior to beginning the initial subsea test for	Rule changes reflect Alternative Compliances that are being issued.	You must…:(4) Perform an initial subsea BOP test. Additional requirements… (i) You must begin the initial subsea BOP test on the seafloor within 30 days of the stump test. (ii) You must submit test procedures with your APD or APM for District Manager approval. (iii) During the pressure test of the BOP, you must pressure test well-control rams and annulars according to (b) and (c) of this section. (iv) You must notify the District

	the BOP system to allow BSEE representative(s) to witness testing. (v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. (vi) You must pressure test the selected rams according to (b) and (c) of this section.		Manager at least 72 hours prior to beginning the initial subsea test for the BOP system to allow BSEE representative(s) to witness testing. (v) You must test and verify closure of at least one set of rams during the initial subsea test through a ROV hot stab. (vi) You must pressure test the selected rams to 250-350 psi and to a minimum of 1,500 psi for 5 minutes each. Or Recommend "following API 53 Fourth Edition, table 7."
§250.737 (d)(5)(i)(A)	What are the BOP system testing requirements? Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet the following testing requirements: (d) Additional test requirements. You must meet the following additional BOP testing requirements: You must (5) Alternate testing pods between control stations (i) For two complete BOP control stations: (A) Designate a primary and secondary station, and both stations must be function-tested weekly;	Industry opposes 737(d)(5)(i)(A) because the current CFR wording requires double functioning of the BOP components each week. The doubling of the amount of functional testing will adversely affect BOP reliability by increasing the wear on BOP components. Industry recognizes the value of detecting component defects through function testing and pressure testing – however, several changes have occurred in GoM that enhance defect	What are the BOP system testing requirements? Your BOP system (this includes the choke manifold, kelly-type valves, inside BOP, and drill string safety valve) must meet the testing requirements outlined in API 53 Fourth Edition.

		reporting such as: Defect failure reporting through Industry JIP and CFR requirements, enhanced reporting to BSEE on operational wells, defect database trending and identification. Industry proposes to work with BSEE to communicate actions taken to eliminate recurring defects to BOP components to justify clarifying the CFR requirements to be aligned with the Standard 53 requirements. Industry proposes to have the clarification be aligned with the 2015 BSEE function testing guidance.	
§250.737 (e)	(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the BSEE District Manager at least 72 hours in advance, to ensure that a representative of BSEE will have access to the location to witness any testing.	The requirements as outlined are impractical for coil operations and present a significant financial burden without justified benefit.	(e) Prior to conducting any shear ram tests in which you will shear pipe, you must notify the BSEE District Manager at least 72 hours in advance, to ensure that a representative of BSEE will have access to the location to witness any testing. Coiled tubing operations do not require such notice but shear test must be documented and certified.

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§250.738 (b) (3-4)	(3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP. (4) You must submit a report from a BAVO to the District Manager certifying that the BOP is fit for service.	As with 250.734 (b), it is uncertain as to what expertise a BAVO would provide when considering and implementing a BOP repair. With regard to replacement or reconfiguring the BOPE, BAVO should be advised that API 53 and other applicable API standards and/or OEM standards will be used as the benchmark for determining if the BOPE is fit for service.	(3) You must receive approval from the District Manager prior to resuming operations with the new, repaired, or reconfigured BOP.
§250.738 (f)	If you encounter the following situation: (f) Plan to install casing rams or casing shear rams in a surface BOP stack; Then you must . . .Test the affected rams before running casing to the rated working pressure or MASP plus 500 psi. The BOP must also provide for sealing the well after casing is sheared. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.	Proposed revision clarifies that if casing rams are installed and tested at initial nipple up, then a re-test is not required prior to running casing.	If you encounter the following situation: (f) Plan to install casing rams or casing shear rams in a surface BOP stack; Then you must . . .Test the affected rams before running casing to the rated working pressure or MASP plus 500 psi. A test at initial nipple up is sufficient, unless it has been over 21 days since casing rams were tested. The BOP must also provide for sealing the well after casing is sheared. If this installation was not included in your approved permit, and changes the BOP configuration approved in the APD or APM, you must notify and receive approval from the District Manager.

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§250.738 (i)	(i) You activate any shear ram and pipe or casing is sheared; Retrieve, physically inspect, and conduct a full pressure test of the BOP stack after the situation is fully controlled. You must submit to the District Manager a report from a BSEE-approved verification organization certifying that the BOP is fit to return to service.	BAVO is not required to achieve the objective of confirming that the BOP is fit to return to service.	(i) You activate any shear ram and pipe or casing is sheared refer to API 53 for requirements.
§250.738 (m)	(m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart; Contact the District Manager and request approval in your APD or APM. Your request must include a report from a BAVO on the equipment's design and suitability for its intended use as well as any other information required by the District Manager. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.	BAVO is not required to achieve this objective. Operators and OEMs are the best suited to provide BSEE an assessment of the additional well control equipment.	(m) Plan to utilize any other well-control equipment (e.g., but not limited to, subsea isolation device, subsea accumulator module, or gas handler) that is in addition to the equipment required in this subpart; Contact the District Manager and request approval in your APD or APM. The District Manager may impose any conditions regarding the equipment's capabilities, operation, and testing.

§250.738 (o)	(o) You install redundant components for well control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines); Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report from a BAVO that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require you to provide additional information as needed to clarify or evaluate your report.	BAVO is not required to achieve this objective. Operators and OEMs are the best suited to provide BSEE an assessment of the well control equipment.	(o) You install redundant components for well control in your BOP system that are in addition to the required components of this subpart (e.g., pipe/variable bore rams, shear rams, annular preventers, gas bleed lines, and choke/kill side outlets or lines); Comply with all testing, maintenance, and inspection requirements in this subpart that are applicable to those well-control components. If any redundant component fails a test, you must submit a report to BSEE that describes the failure and confirms that there is no impact on the BOP that will make it unfit for well-control purposes. You must submit this report to the District Manager and receive approval before resuming operations. The District Manager may require you to provide additional information as needed to clarify or evaluate your report.
§250.739(b)	(b) A complete breakdown and detailed physical inspection of the BOP and every associated system and component must be performed every 5 years. This complete breakdown and inspection may be performed in phased intervals. You must track and	A “complete breakdown” is impractical. This has already been clarified by BSEE, the following was posted on July 1, 2016: “BOP equipment must be broken down to allow for an appropriately detailed physical	(b) A major, detailed physical inspection of the BOP equipment must be performed every five years or when indicated by equipment condition (condition based maintenance). BOP equipment must be sufficiently disassembled

	document all system and component inspection dates. These records must be available on the rig. A BAVO is required to be present during each inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This complete breakdown and inspection must be performed every 5 years from the following applicable dates, whichever is later: (1) The date the equipment owner accepts delivery of a new build drilling rig with a new BOP system; (2) The date the new, repaired, or remanufactured equipment is initially installed into the system; or (3) The date of the last 5- year inspection for the component.	inspection. This requirement does not mean that each component must be dismantled to its smallest possible part. OEM-approved methods (e.g., x-ray or ultrasonic) can be utilized to assist in the detailed inspection." Also, as written the major inspection must be performed every five years. Some components may never need a detailed tear down and inspection (visual may be sufficient) other components may need a detailed inspection much sooner than five years (e.g., due to usage in severe conditions). It is generally understood that scheduling inspection and maintenance based on equipment condition can have many advantages (e.g., brake pad and tire maintenance on automobiles). It is requested that scheduling inspection and maintenance based on condition be allowed as an alternative to the 5 year requirement. Remove "complete breakdown" from final language	to allow for an appropriately detailed physical inspection as recommended by the OEM. This inspection may be performed in phased intervals. You must track and document all system and component inspection dates. These records must be available on the rig. A third party inspection company representative is required to review inspection results and compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make these reports available to BSEE upon request. This report must be submitted every 5 years from the following applicable dates, whichever is later: (1) The date the equipment owner accepts delivery of a new build drilling rig with a new BOP system; (2) The date the new, repaired, or remanufactured equipment is initially installed into the system; or (3) The date of the last major inspection for the component.
Provisions to Retain			

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§250.462 (a)	For drilling operations using a subsea BOP or surface BOP on a floating facility, you must have the ability to control or contain a blowout event at the sea floor. (a) To determine your required source control and containment capabilities you must do the following: (1) Consider a scenario of the wellbore fully evacuated to reservoir fluids, with no restrictions in the well. (2) Evaluate the performance of the well as designed to determine if a full shut-in can be achieved without having reservoir fluids broach to the sea floor. If your evaluation indicates that the well can only be partially shut-in, then you must determine your ability to flow and capture the residual fluids to a surface production and storage system.	Need to do well control analysis based on what the well is designed for.	
§250.462 (d)	You must contact the District Manager and Regional Supervisor for reevaluation of your source control and containment capabilities if your: (1) Well design changes, or (2) Approved source control and containment equipment is out of service.	Industry has reviewed and accepted BSEE FAQ answers to clarify.	

Attachment

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