Pacific Drilling Services, Inc.
11700 Katy Freeway / Suite 175
Houston / Texas / 77079
Ph / 713 334-6662 Fax / 713 583-5777

Web / www.pacificdrilling.com

14 July 2015

Via electronic submission to: http://www.regulations.gov/

Department of the Interior
Bureau of Safety and Environmental Enforcement
Attention: Regulations and Standards Branch
45600 Woodland Road
Sterling, VA 20166

Re: *Blowout Preventer Systems and Well Control, 1014–AA11*

To whom it may concern:

Pacific Drilling owns and operates ultra-deep water drill ships both in the Gulf of Mexico and worldwide.

This document lists our comments and suggested alternate text from on the proposed regulatory changes to Blowout Prevention Systems and Well Control requirements in 30 C.F.R. § 250 that have the potential to directly affect Pacific Drilling as a drilling contractor.

We have not, generally, commented on the sections that we have no issues with or that do not affect us directly, though we understand that there will be some knock-on-affect from rules that directly impact the lessees.

In our comments we have focused on the requirements rather than the costs. We fully agree that offshore operations must be conducted safely and in a manner that protects people and the environment. If we get the safety aspects correct then the economics will sort themselves out.
However we have grave concerns that the proposed rules as written do not meet the real intent of the Bureau and will, in many instances, actually make us less safe than we are today. We suggest that workshops should be arranged for BSEE and industry to discuss actual meanings and create rules that will meet our common intent and make us safer while reducing the probability of unintended consequences.

Sincerely

Cees van Diemen

Executive VP and Chief Operations Officer

Table of Contents

Summary of our top issues (as requested by the Assistant Secretary):

250.739 (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 not be performed in phased intervals**. (See page 42 of this document)

> *We have no problem with the requirement for the inspection of the BOP every five years. This is, and has been, a requirement of API S53 which we do follow. Your proposed requirement of carrying out the inspection of 'the BOP and every associated system and component' all at one time is the issue.*
> *Not only does the infrastructure not currently exist to allow an 'at one time' inspection to take place, but the vagueness of 'every associated system and component' prevents auditable compliance.*
> *As in existing continuous machinery survey scenarios, on-board inspections shall be performed by a competent person(s) witnessed and documented by either a licensed Chief Engineer or a competent third party.*

250.734 (3) Have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface. (See page 20 of this document)

> *The estimated cost that we have been able to put together in the limited available time suggests that this will cost $7million per stack, yet we do not see any safety benefit whatsoever in the requirement. If power from surface is lost then we should make the well safe immediately and not try operating everything for the sake of it. A bigger issue is the weight (4 tons each) and size (67 cu/ft each) of the additional accumulators and trying to find the space to install them while remaining within the capacities of the handling equipment. Some of our peers are using remote accumulators connected by ROV using hoses; we believe the risk factor with this single point failure to be contrary to the safety benefits that we are trying to impose.*

250.735 (a) A surface accumulator system that provides 1.5 times the volume of fluid capacity 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 all BOP functions without assistance from a charging system, with the blind shear ram being the last in the sequence, and still have enough pressure to shear pipe and seal the well with a minimum pressure of 200 psi remaining on the bottles above the precharge pressure. (See page 31 of this document)

> *This would require us to add 50 accumulator bottles to the surface system and then increase the size of the BOP fluid, glycol and mixed fluid tanks to meet the API requirements for the total stored fluid volumes. The cost of the project is not the driver of our objection, but the real estate requirements are; in common with most drilling vessels, the BOP control system is integrated during construction and to replace it, or modify it, later is very difficult. This is exacerbated by the lack of understanding of this proposal. Why would anybody want to be able to operate the entire stack and then shear pipe in the knowledge that we had lost all rig power?*

250.734 (6) (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 shearing efficiency. (See page 25 of this document)

The danger of this is that it could severely restrict our ability to operate. The riser tensioners have a fixed stroke which limits how far off location we can be. The Emergency Disconnect Sequence consumes time and therefore distance. In a typical water depth of 6,890ft we have to begin the sequence at 278ft from the well centre and this is based on a standard 54 second EDS. The proposed rule wants two shears with an interim delay. My best estimate is that this will increase the EDS time to 100 seconds reducing this distance by 77ft. Our DP system has an accuracy of 16ft so we could have only 270ft (160 seconds) from normal operation to disconnecting which, while possible, does not leave any time for discussion.
The intent of the EDS is for us to release the vessel from the well to save lives. If we can do this without polluting, then that is a bonus, but we want to save lives first. The operation at the time together with the weather conditions etc., should dictate what Emergency Disconnect Sequence should be selected, not a prescriptive rule.

250.730 (b) …. The training and qualification of repair and maintenance personnel must meet or exceed any OEM training recommendations unless otherwise directed by BSEE. (See page 9 of this document)

and

250.739 (d)You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, meet the qualification and training criteria specified by the OEMs and recognized engineering practices. (See page 44 of this document)

The BOP equipment OEMs do not publish and qualification or training criteria for their personnel. Our subsea personnel are competent for their positions and have all undergone specific BOP and BOP control system operation and maintenance training by both the OEMs and some specialist training companies.

Subpart G—Well Operations and Equipment General Requirements

Rig Requirements

250.711 What are the requirements for well-control drills?

250.711 (a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively.

PACIFIC DRILLING COMMENT:
We feel that the last sentence renders this unnecessarily over prescriptive. If we are drilling ahead, for example, for more than two weeks then it should not be disallowed to repeat a drill that is appropriate to this ongoing operation.

PACIFIC DRILLING SUGGESTED TEXT
250.711 (a) Timing of drills. You must conduct each drill during a period of activity that minimizes the risk to operations. The timing of your drills must cover a range of different operations, including drilling with a diverter, on-bottom drilling, and tripping. The same drill may not be repeated consecutively unless the ongoing operation has not changed since the previous drill.

-----0-----

Well Operations

250.724 What are the real-time monitoring requirements?

250.724 (a) When conducting well operations with a subsea BOP or surface BOP on a floating facility or when operating in an HPHT environment you must, within 3 years of publication of the final rule, gather and monitor real-time well data using an independent, automatic, and continuous monitoring system capable of recording, storing, and transmitting all aspects of:
(1) The BOP control system;
(2) The well's fluid handling systems on the rig; and
(3) The well's downhole conditions with the bottom hole assembly tools (if any tools are installed).
250.724(b) You must immediately transmit these data as they are gathered to operations where they must be monitored by qualified personnel who must be in continuous contact with rig personnel during operations. After operations, you must preserve and store this data at a designated location for recordkeeping purposes as required in §§ 250.740 and 250.741. You must designate the location where the data will be stored and monitored during operations in your APD or APM. The location and the data must be made accessible to BSEE upon request.
250.724(c) If you lose any real-time monitoring capability during operations covered by this section, you must immediately notify the District Manager.
The District Manager may require other measures until real-time monitoring capability is restored.

PACIFIC DRILLING COMMENT:
This needs clarification to make it auditable.
What exactly is meant by 'all aspects of'?
What, from a shore based monitoring perspective, are qualified personnel, and where do we find them? (Most of the really qualified personnel have spent their careers offshore and do not want to change to an onshore office environment).
What is expected by 'continuous contact with rig personnel'? Does this mean e-mail capability?
If we lose communications then we may not be able to contact the District Manager.

PACIFIC DRILLING SUGGESTED TEXT
250.724 (a). When conducting well operations with a subsea BOP or surface BOP on a floating facility, or when operating in an HPHT environment, you must gather and monitor real-time well data using a system capable of recording, storing, and transmitting data as identified in a Real Time Monitoring Plan. Within 3 years of publication of the final rule, the Real Time Monitoring Plan must address; (1) the fluid circulating system and (2) bottom hole tools. Within 5 years of publication of the final rule, the Real Time Monitoring Plan must address BOP status.

PACIFIC DRILLING ECONOMICS

The cost of installation – per rig – for a BOP (only) monitoring system is in the order of $226,000 plus $78,000 annual subscription – per rig.

-----0-----

Blowout Preventer (BOP) System Requirements

250.730 What are the general requirements for BOP systems and system components?

250.730 (a) You must design, install, maintain, inspect, test, and use the BOP system and system components to ensure well control. The working-pressure rating of each BOP component must exceed MASP as defined for the operation. For a subsea BOP, the MASP must be 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. Each ram (excluding casing shear/supershear) must be capable of closing and sealing the wellbore at all times, including under flowing conditions as defined for the operation and 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 you 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) The following industry standards (all incorporated by reference in § 250.198):
(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.
(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 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.

PACIFIC DRILLING COMMENT:
Neither the drilling contractor nor the operator typically 'designs' the BOP equipment. The BOP and BOP system components are designed in accordance with API 6A, API 16A, API 16C, API 16D, API 17D and other industry standard specifications. The drilling contractor selects such equipment from OEMs and has their BOP stack built in accordance with API S53 7.1.2 and installs in on his rig. The drilling contractor then markets the rig and its equipment to the operators who select a rig for their campaign based, amongst other criteria, on the installed equipment capabilities prior to any well commencing.
This rule would be better stating that you must ensure that the selected drilling rig is appropriately equipped for the wells to be drilled.

If the intent is that we should be capable to close and seal the wellbore at all times, then better wording would be ' Each BOP stack must be capable of closing and sealing the wellbore at all times'.
If we make any changes to the BOP stack or control system then we must be between wells and as such any changes to the drawings and equipment would be included in the APD for the next well.

PACIFIC DRILLING SUGGESTED TEXT

250.730 (a) You must ensure that the selected drilling rig, specifically including the BOP stack, the BOP control system and associated systems, is appropriately equipped for the contracted drilling campaign. The BOPs and system components must be maintained, inspected, tested and operated in accordance with API S53, as incorporated in 250.198. Each BOP stack must be capable of closing and sealing the wellbore at all times, including under flowing conditions as defined for the operation and 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 you may encounter.

(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) The following industry standards (all incorporated by reference in § 250.198):

(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.

3. All BOP stacks must have the capability and sufficient redundancy of pipe rams to have at least two rams (variable or fixed) that can close and seal on the body of any regular drill pipe or tubing that is run through the BOP stack at pressures up to and including the Rated Working Pressure (RWP) of the equipment.

(4) The current set of approved schematic drawings must be available on the rig and at an onshore location.

-----0-----

250.730 (b) You must design, fabricate, maintain, and repair your BOP system according to the requirements contained in this subpart, OEM recommendations unless otherwise directed by BSEE, and recognized engineering practices. The training and qualification of repair and maintenance personnel must meet or exceed any OEM training recommendations unless otherwise directed by BSEE.

PACIFIC DRILLING COMMENT:
The 'Design and fabricate' references are out of scope here. The BOP stack is what it is and should only be used on the appropriate wells.
The OEMs publish maintenance recommendations, but as their manuals are 'one size fits all' and they do not have a clear understanding of how the equipment has been used, maintained or preserved, their recommendations are directed to the lowest common denominator of user. The deepwater, and some other, equipment owners have teams of full time competent operational and maintenance personnel who have created the 'Equipment Owner's' maintenance standards based on (OEM and other) training, experience and a detailed knowledge of the specific use, maintenance and preservation principles for their specific equipment. This is covered by API S53 7.6.9.3.

PACIFIC DRILLING SUGGESTED TEXT

250.730 (b) You must maintain, and repair your BOP system according to the requirements contained in API S53, and recognized engineering practices. The competence of maintenance personnel must meet or exceed any OEM recommendations unless otherwise directed by BSEE.

-----0-----

250.730 (c) You must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A, and: (1) You must provide a written report of equipment failure to the manufacturer of such equipment within 30 days after the discovery and identification of the failure.

PACIFIC DRILLING COMMENT:
The 'Group of Seven' drilling contractors are already reporting all failures, which we define as the inability of the equipment to function as defined, to a common database fulfilling the requirements mentioned above. Discussions are ongoing to expand this across the industry. These failures are automatically copied to the OEM by the database as they are reported.

PACIFIC DRILLING SUGGESTED TEXT

250.730 (c) If you are not included in the 'Group of Seven' database then you must follow the failure reporting procedures contained in API Standard 53, ANSI/API Spec. 6A, and ANSI/API Spec 16A within 30 days of the discovery and identification of the failure.

-----0-----

250.730 (2) You must ensure that an investigation and a failure analysis are initiated within 60 days of the failure to determine the cause of the failure. If the investigation and analysis are performed by an entity other than the manufacturer, you must ensure that the manufacturer receives a copy of the analysis.

PACIFIC DRILLING COMMENT:
Not every failure warrants a full investigation. We report everything – even if we have installed a seal upside down which caused a circuit to leak. Our objective is to build data to show that, for example, sufficient people have duplicated this error (across all rigs involved in the database) to warrant a redesign of the seal and the groove to prevent such occurrences on future generations of equipment. Within a year or so we should have sufficient data to allow us to clearly see exactly what our weaknesses are and then we can collectively focus on these areas until we achieve all of the design and procedure changes required to make well control equipment even more reliable.
Any major failure is discussed directly with the OEM and an investigation initiated ASAP. The system would fail if every (minor) failure required investigation by either the OEM, a third party or a combination of both. Repeat failures warrant changes to the equipment, not repeat investigations.

SUGGESTED TEXT
250.730 (2) If a failure analysis is warranted and it is NOT repeat of a previously documented failure for which a failure analysis was performed, or if the failure is a result of normal anticipated wear then you must ensure that the OEM is supplied with all relevant information to start an investigation and failure analysis within 60 days of the failure. In all situations the failure must be reported, even if it is a repeat failure.

-----0-----

250.730 (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 notice or change, report the design change or modified procedures in writing to the Chief, Office of Offshore Regulatory Programs; Bureau of Safety and Environmental Enforcement; HE 3314; 45600 Woodland Road, Sterling, Virginia 20166.

PACIFIC DRILLING COMMENT:
Design changes brought about by a failure are usually notified to the industry by use of a Safety Alert and these are followed up as appropriate, bearing in mind that most of these changes do not need to be made until the next scheduled service interval or the next time the equipment is at the OEM's facility.
There is the potential for confusion and/or lost transmittals if multiple addressees are used for communications. It will be better if we send everything to a single address.

SUGGESTED TEXT
250.730 (3) If the equipment manufacturer notifies you that it has changed an equipment design, or if you have changed operating or repair procedures as a result of a failure, then you must, within 30 days of such notice or change, report the design change and/or modified procedures in writing to the District Manager.

---0---

250.731 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 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.

250.731 (c) Certification by a BSEE-approved verification organization, Verification that:
(1) Test data clearly demonstrates 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 at the most extreme anticipated conditions; and
(3) The accumulator system has sufficient fluid to function the BOP system without assistance from the charging system.

PACIFIC DRILLING COMMENT:
The BSEE Approved Verification Organizations do not currently exist and we do not know when they will. To compel us to provide any information from an organization that will not exist until the rule is published could have a major economic impact.
If BSEE must approve the verification organization and the operators/contractors have to hire them, then who is independent from who? Will this create potential conflicts of interest and render the third party neutrality ineffective?
How do we define 'most extreme anticipated conditions'?
What functions?
All references to BSEE approved verification organizations should be removed/deleted due to potential legal implications and restriction of trade.

PACIFIC DRILLING SUGGESTED TEXT
250.731 (c) Certification by a qualified independent third party, Including: verification that:
(1) Test data and supporting engineering calculations clearly demonstrates 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 at the anticipated conditions; and
(3) The accumulator systems shall be in accordance with API 16D.

-----0-----

250.731 (d) Additional certification by a BSEE-approved verification organization, 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. Including: Verification that:

(1) The BOP stack is suitable for use with 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.

PACIFIC DRILLING COMMENT:

BOP stacks are not typically moved from rig to rig. They are part of the rig equipment and as such selected to suit the rig design and capabilities.

The BAVOs do not currently exist and we do not know when they will. To compel us to provide any information from an organization that will not exist until the rule is published could have a major economic impact.

What will be the procedure if a stack has been compromised or damaged? Can the BAVO certify it?

All references to BSEE approved verification organizations should be removed/deleted due to potential legal implications and restriction of trade.

SUGGESTED TEXT

250.731 (d) Additional certification by a qualified independent third party, if you use a subsea BOP, a BOP in an HPHT environment as defined in § 250.807 (wellhead pressure greater than 15,000psi or wellhead temperature higher than 3500F), or a surface BOP on a floating facility. Including: Verification that:

(1) The BOP stack is suitable for use with 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.

-----0-----

250.731 (f) Certification stating that the Mechanical Integrity Assessment 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.

PACIFIC DRILLING COMMENT:
Is this only due if an APD has NOT been requested in the previous 12 months? If it is in addition to then it appears to be an unnecessary time and expense burden.
All references to BSEE approved verification organizations should be removed/deleted due to potential legal implications and restriction of trade.

PACIFIC DRILLING SUGGESTED TEXT:
250.731 (f) Delete; This report is unnecessary as all of the requested information is already being reported in the APD/APM and the BOP and Well Compatibility Certificate.

-----0-----

250.732 What are the BSEE-approved verification organization requirements for BOP systems and system components?

250.732(a) The BSEE will maintain a list of BSEE-approved verification organizations that you may use. For an organization to become a BSEE approved verification organization, it must submit the following information to the Chief, Office of Regulatory Programs: Bureau of Safety and Environmental Enforcement: 45600 Woodland Road, Sterling, Virginia, 20166, for BSEE review and approval:
(1) Previous experience in verification or in the design, fabrication, installation, repair, or major modification of BOPs and related systems and equipment;
(2) Technical capabilities;
(3) Size and type of organization;
(4) In-house availability of, or access to, appropriate technology. This should include computer programs, hardware, and testing materials and equipment;
(5) Ability to perform the verification functions for projects considering current commitments;
(6) Previous experience with BSEE requirements and procedures; and
(7) Any additional information that may be relevant to BSEE's review.
(b) Prior to beginning any operation requiring the use of any BOP, you must submit verification by a BSEE-approved verification organization and supporting documentation as required by this paragraph to the appropriate District Manager and Regional Supervisor.

PACIFIC DRILLING COMMENT:
BAVOs do not currently exist.
Is there risk of a restriction of trade scenario for the audit companies that do not meet all of the above criteria?
Can a company really be excluded because they have never worked for BSEE in the past?
What is appropriate technology? What computer programs? What hardware, testing materials and equipment?
Was this list of criteria written with a specific company in mind?
Will BSEEs approval of each of these organizations mean that BSEE will be fully accountable for the BAVO's opinions and judgments?
All references to BSEE approved verification organizations should be removed/deleted due to potential legal implications and restriction of trade.

PACIFIC DRILLING SUGGESTED TEXT:
250.732 All of section 250.732 references to BSEE approved verification organizations should be removed/deleted due to potential legal implications and restriction of trade.

-----0-----

250.734 What are the requirements for a subsea BOP system?

250.734(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 conducting operations if the well is already deepened beyond the surface casing point. The 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:
250.734(1) Have at least five remote-controlled, hydraulically operated BOPs; You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams. For the two shear ram requirement, you must comply with this requirement within 5 years from the publication of the final rule.
(i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MASP, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.
(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 that includes 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 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 rams must be installed below the sealing shear rams.

PACIFIC DRILLING COMMENT:
We do not understand why non-hydraulically operated BOPs should be excluded from this rule. Any non-sealing shear ram must be installed below at least one sealing shear ram.
The 5-year implementation needs to extend beyond the "two shear ram requirement" to the applicability of the whole section in order to allow for the general introduction of technology to allow for the shearing of flat packs, slick-line, etc.
General comment needs to be developed on MASP – Not to exceed the rated pressure of the sealing preventer above the uppermost shear ram.
Discussion on use of MAWHP vs. MASP for both subsea and surface. MASP , as used by BSEE, is not the appropriate industry term for subsea use.

PACIFIC DRILLING SUGGESTED TEXT:
You must comply with this requirement within 5 years from the publication of the final rule.
When operating with a subsea BOP system, you must:

250.734 (1) Have at least five remote-controlled, hydraulically operated BOPs;
(2) You must have at least one annular BOP, two BOPs equipped with pipe rams, and two BOPs equipped with shear rams.
(i) Both BOPs equipped with pipe rams must be capable of closing and sealing on the tubular body of any drill pipe, workstring, and tubing under MAWHP, not to exceed the rated pressure of the sealing preventer above the uppermost shear ram, as defined for the operation, excluding the bottom hole assembly that includes heavy-weight pipe or collars, and bottom-hole tools.

(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 that includes 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 under MAWHP, not to exceed the rated pressure of the sealing preventer above the uppermost shear ram. At least one shear ram must be capable of sealing the wellbore after shearing under MAWHP conditions as defined for the operation. Any non-sealing shear rams must be installed below at least one set of the sealing shear rams.

-----0-----

250.734 (2) Have an operable dual-pod control system to ensure proper and independent operation of the BOP system;

PACIFIC DRILLING COMMENT:
The wording of this tightly ties the industry to the current methodology without room to change/improve etc.

PACIFIC DRILLING SUGGESTED TEXT:
250.734 (2) Have a fully redundant subsea control system to ensure proper and independent operation of the BOP system;

-----0-----

250.734 (3) Have the accumulator capacity located subsea, to provide fast closure of the BOP components and to operate all critical functions in case of a loss of the power fluid connection to the surface;
The accumulator capacity must:
(i) Function each required shear ram, choke and kill side outlet valves, one pipe ram, and disconnect the LMRP.
(ii) Have the capability of delivering fluid to each ROV function i.e., flying leads.
(iii) Have dedicated independent bottles for the autoshear, deadman, and EDS systems.
(iv) Perform under MASP conditions as defined for the operation.

PACIFIC DRILLING COMMENT:
If fast closure is defined as meeting API S53 7.4.6.5.4 then simply say so and allow individual rigs to determine if subsea accumulator capacity is required to meet the time. In most cases this will not be so.
If there is a loss of the power fluid connection to surface then we have also probably lost control from surface and there is no logical reason to require the ability to operate all choke and kill outlet valves in such a scenario.
Some companies are suggesting the use of remote subsea accumulators connected to the stack by the ROV using a hose. We see this as additional risk due to the vulnerable single point failure of this remote connection.
The critical functions require a flying lead type solution to meet the API S53 closing times.
The dedicated Emergency Accumulator supplies the Emergency (Deadman/Autoshear/EHBS) systems and the Secondary (ROV and Acoustic) systems. The EDS is typically powered from surface with the prime intention of preserving subsea fluid for those functions/sequences that cannot be powered from surface.

SUBSEA ACCUMULATOR	BSEE Proposed	Pacific Zonda existing	Additional Requirements to meet BSEE proposal
Subsea accumulators	2 x 80 USG piston accumulators	2 x 80 USG piston accumulators	0
EHBS(deadman/Autoshear) accumulators	6 x 20.6 USG depth compensating bottles	6 x 20.6 USG depth compensating bottles	0
EDS dedicated accumulators	6 x 20.6 USG depth compensating bottles	0	6 x 20.6 USG depth compensating bottles
Acoustic dedicated accumulator	6 x 20.6 USG depth compensating bottles	0	6 x 20.6 USG depth compensating bottles
EDS non-shear accumulator	2 x 150 USG piston accumulators	0	2 x 150 USG piston accumulators
Acoustic accumulator	2 x 150 USG piston accumulators 1 x 80 USG piston accumulator	2 x 150 USG piston accumulators 1 x 80 USG piston accumulator	0

PACIFIC DRILLING SUGGESTED TEXT:

250.734 (3) Have an accumulator system designed to provide closure of the BOP components to secure the well within the response times specified in API S 53 in case of the loss of the power fluid connection to the surface.

Additional requirements: within five years of the publication of the final rule, the accumulator capacity must be sufficient to:

(i) Shear pipe and seal the well, and

(ii) Have accumulator bottles that are dedicated to the largest capacity requirement of either the autoshear or deadman functions.

PACIFIC DRILLING ECONOMICS

The above DCB accumulators cost $304,000 each and the piston accumulators $106,000 each- $3,860,000 in total plus piping and installation. The installation can only be estimated at this time as it will require massive frame modifications. A ballpark figure for this is $2,000,000 but will be dependent on final calculations because we may have to increase the BOP stack crane and trolley capacity on the rig to accommodate it.

In common with most of the big purchase requirements to fulfill this rule, delivery times will be long with the consequential possibility of lost time while we wait for them.

-----0-----

250.734 (4) Have a subsea BOP stack equipped with remotely operated vehicle (ROV) intervention capability;
The ROV must be capable of performing critical functions, including opening and closing each shear ram, choke and kill side outlet valves, all pipe rams, 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).

PACIFIC DRILLING COMMENT:
Additional ROV functions create many possible single-point failure and additional leak paths potentially decreasing system reliability.
Additional panels reduce availability of ROV access; they also reduce the access for maintenance activities on the stack.
Availability of equipment to meet the proposed requirement within 3 months of publication isn't possible.

PACIFIC DRILLING SUGGESTED TEXT:
250.734 (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 S53 7.4.16.1.1, under MAWHP 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).

PACIFIC DRILLING ECONOMICS

One ROV API 17 H compliant receptacle, complete with shuttle valve, piping and installation, is in the region of $10,000. Twenty three such additional receptacles will cost $230,000.

-----0-----

250.734 (5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The crew must examine all ROV related well-control equipment (both surface and subsea) to ensure that it is properly maintained and capable of shutting in the well during emergency operations;
The crew must be trained in the operation of the ROV. The training must include simulator training on stabbing into an ROV intervention panel on a subsea BOP stack. The ROV crew must be in communication with designated rig personnel who are knowledgeable about the BOP's capabilities.

PACIFIC DRILLING COMMENT:
The ROV crews do not have any well control equipment to maintain, but they should become familiar with the ROV panels on the stack (under the supervision of the subsea team).
The ROV crew must undergo the necessary training to become competent to correctly stab into the BOP stack functions and to operate ROV valves using a manipulator as directed.

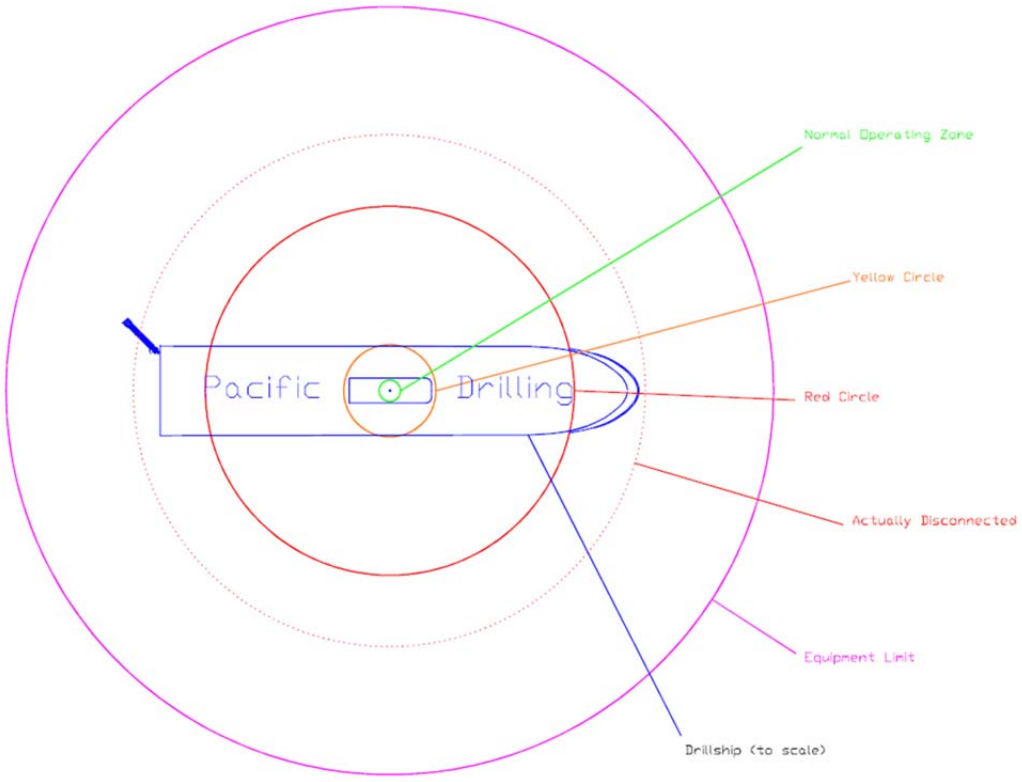
PACIFIC DRILLING SUGGESTED TEXT:
250.734 (5) Maintain an ROV and have a trained ROV crew on each rig unit on a continuous basis once BOP deployment has been initiated from the rig until recovered to the surface. The ROV crew must be familiar with all ROV related equipment (both surface and subsea) to ensure that it is properly maintained and capable of carrying out appropriate tasks during emergency operations;
The crew must be trained in the operation of the ROV. The training must include competence training on stabbing into an ROV intervention panel and operating the type(s) of ROV valves that are mounted on the BOP stack. Whenever the ROV is deployed to the BOP stack the ROV crew must be able to be in constant communication with designated rig personnel who are knowledgeable about the BOP's capabilities.

-----0-----

250.734 (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 close at a minimum, two shear rams in sequence and be capable of performing their 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 shearing efficiency.
(vi) The control system for the emergency functions must be a fail-safe design, and the logic must provide for the subsequent step to be independent from the previous step having to be completed.

PACIFIC DRILLING COMMENT:
To rule that each emergency system must always close two shear rams in sequence will reduce the operating capability of the rigs due to the reduced operating radii induced by such a rule. Watch, or operating, circles in deep water are limited by the stroke of the riser tensioners. If we have to allow sufficient time to close two sets of shear rams with a delay between them, then in many situations we will have to reduce our zone of operation to an unfeasibly small size preventing reasonable drilling operations. This ruling also puts our equipment at risk by potentially damaging both sets of shear rams before we have had a chance to analyze the situation to control the well in a reasoned manner.
To rule that the EDS must also seal the well on every occasion is also very restricting and contradicts our major premise that the safety of the rig personnel is our prime focus. Preventing pollution is secondary.
Whether a system is considered rapid discharge or not has nothing to do with the achieved performance if the circuits are designed accordingly.

Water Depth	6,890	ft.
Wellhead stick-up	10	ft.
Visible tensioner rod at setup	6.25	ft.
Visible TJ inner Barrel at setup	19.35	ft.
Projected drift speed	2.620	ft/sec.
EDS-3 Casing shear and pipe shear disconnect	100	secs.
TJ hidden inner barrel	50.65	ft.
Equipment Limit due to tensioner stroke.	590	ft.
Equipment Limit due to TJ stroke.	841	ft.
Equipment Limit due to the Lower Flex Jt.	1,202	ft.
OFFSET TO EQUIPMENT LIMIT	**590**	**ft.**
Time to reach equipment limit	3.76	minutes
Wellhead to Rotary Table	6,959	ft.
Rotary Table to Water line	78.61	ft.
Vessel draft	37	ft.
Stack height	48.13	ft.
Flex joint connected limit	10	degrees
Normal Operating Zone	16	ft.
Yellow Circle	43	ft.
Red Circle	128	ft.
Actually Disconnected (based on the red circle)	390	ft.
Absolute Equipment Limit	590	ft.



An operational risk assessment determines the optimum emergency sequence for the specific operation to be performed, and this is too prescriptive a requirement in the shearing sequential requirement (there are many differences between an EDS selected sequence and the use of the deadman/autoshear). The prescribed method in the proposed rule may not be the safest method to undertake.
'Failsafe design' and 'logic circuits' do not sit well together. Simplicity is best.

PACIFIC DRILLING SUGGESTED TEXT:
250.734 (6) Provide autoshear and deadman, or EHBS, systems for all floating rigs plus EDS systems for dynamically positioned 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.
(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.
(iii) Emergency Disconnect Sequence (EDS) system means a safety system that is designed to be manually activated to disconnect the LMRP in the event of an emergency situation.
(iv) Each emergency function or sequence must operate as designed, under MAWHP conditions, and as detailed in the APD.
(v) If your sequence calls for two shear rams to close, then your sequencing must allow a sufficient delay for closing the first shear ram before beginning closure of the second shear ram to provide for maximum shearing efficiency.

-----0-----

250.734 (7) Demonstrate that any acoustic control system will function in the proposed environment and conditions; If you choose to install an acoustic control system in addition to the autoshear, deadman, and EDS requirements, you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic system will function in the proposed environment and conditions. The District Manager may require additional information.

PACIFIC DRILLING COMMENT:
Beware of unintended consequences. If a failure of the acoustic system results in a mandatory stack pull for repairs, then industry will be encouraged to reduce the emergency capability of the rig by removing the acoustic system. As per proposed section 250.738(o) acoustic systems will be treated as a redundant system as described in the text.

PACIFIC DRILLING SUGGESTED TEXT:
250.734 (7) If you choose to add an optional acoustic control system to your subsea BOP stack secondary control system, then you must demonstrate to the District Manager, as part of the information submitted under § 250.731, that the acoustic system will function in the proposed environment and conditions. The District Manager may require additional information.

-----0-----

250.734 (11) Establish minimum requirements for personnel authorized to operate critical BOP equipment;
Personnel must have:
(i) Training in deepwater well-control theory and practice according to the requirements of Subpart O; and
(ii) A comprehensive knowledge of BOP hardware and control systems.

PACIFIC DRILLING COMMENT:
This document should clearly spell out the understanding of "critical BOP equipment" to align with API S53.
"Competent person required in S53.
This is being addressed by IADC and OEM's to develop but currently not addressed in any API specific document."

PACIFIC DRILLING SUGGESTED TEXT:
250.734 (11) Establish minimum requirements for personnel authorized to operate critical BOP equipment;
Personnel must have:
(i) Training in deepwater well-control theory and practice according to the requirements of Subpart O; and
(ii) A knowledge of BOP hardware and control systems commensurate with their responsibilities.

-----0-----

250.734 (12) Before removing the marine riser, displace the fluid in the riser with seawater; You must maintain sufficient hydrostatic pressure or take other suitable precautions to compensate for the reduction in pressure and to maintain a safe and controlled well condition. You must follow the requirements of § 250.720(b).

PACIFIC DRILLING COMMENT:
This is poorly written as it does not allow for an EDS type scenario.

PACIFIC DRILLING SUGGESTED TEXT:
250.734 (12) Before removing the marine riser, other than in an emergency situation, displace the fluid in the riser with seawater using a closed volumetric visual control system to observe for any fluid gains/losses. Transfer of fluid out, or into the closed system is not allowed.
You must follow the requirements of § 250.720(b).

-----0-----

250.734 (15) Install a gas bleed line with two valves for the annular preventer;
(i) The valves must hold pressure from both directions;
(ii) If you have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, you must install a gas bleed line on each annular.

PACIFIC DRILLING COMMENT:
There is no argument that the valves should all hold pressure from both directions, but the cost of adding gas bleed valves to some stacks will be enormous and requiring new annular preventers for some installations. If this rule passes as it is, then some rigs will take the affordable option and reduce capability by removing the lower annular from the stack.

PACIFIC DRILLING SUGGESTED TEXT
250.734 (15) If you plan to use a BOP stack manufactured after the effective date of this regulation, and you will have dual annulars, where one annular is on the LMRP and one annular is on the lower BOP stack, you must install a gas bleed line with two bidirectional valves under each annular.

-----0-----

250.734 (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, including connection, 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 within 7 years from the publication of the final rule;
(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.

PACIFIC DRILLING COMMENT:
Why be so prescriptive? If the intent is simply that the shear rams must be able to sever the pipe, and seal, regardless of where the pipe is within the bore then simply say so. If the pipe does not need to be centralized to shear it then why demand it?
Any batteries installed in any subsea control equipment that are required for the operation of any system must have the capability of being monitored from surface.

PACIFIC DRILLING SUGGESTED TEXT:
250.734 (16) Use a BOP system that has the following capabilities:
(i) A shear ram design that can sever the pipe regardless of its position within the bore of the stack This may be achieved by a mechanism attached to the ram that moves the pipe or it may be that the ram design can simply shear the pipe where it is, but the mechanism cannot be another ram BOP or annular preventer, though you may use those during a planned shear. You must have this capability within 7 years from the publication of the final rule;
(ii) The ability to mitigate compression of the pipe stub between the shearing rams when both shear rams are closed;
(iii) All batteries within subsea components of the BOP control systems that can affect the operation of the equipment must be continuously monitored from the drilling rig, to ensure that there is sufficient battery power to operate the system.

-----0-----

250.735 What associated systems and related equipment must all BOP systems include?

All BOP systems must include the following associated systems and related equipment:

250.735(a) A surface accumulator system that provides 1.5 times the volume of fluid capacity 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 all BOP functions without assistance from a charging system, with the blind shear ram being the last in the sequence, and still have enough pressure to shear pipe and seal the well with a minimum pressure of 200 psi remaining on the bottles above the precharge 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;

PACIFIC DRILLING COMMENT
In the event of a power loss the BOP stack would only be used to make the well safe until power was restored. There is no sense in providing sufficient power to run a well kill operation if the mud pumps and drawworks etc., are also without power. If it is necessary to shear pipe then that ought to be the first action, not the last.
To require a typical surface accumulator system to be increased in size by 50 x 15USG bottles;

SURFACE ACCUMULATOR	BSEE Proposed	Pacific Zonda existing	Additional Requirements to meet BSEE proposal
Total BOP volume required	559.77 USG	458.07 USG	104.96 USG
Subsea volume available	23.86 USG	23.86 USG	0 USG
Net minimum surface useable volume req.d	535.91 USG	434.21 USG	101.7 USG
Total stored fluid volume	750.28 USG	607.89 USG	142.39 USG
Non-useable volume	215.52 USG	173.68 USG	41.84 USG
Surface accumulators	114 x 15 USG bladder accumulators	64 x 15 USG bladder accumulators	50 x 15 USG bladder accumulators

Compliance with this proposed rule, affects not only the quantity of accumulator bottles but also the tank size (which per API 16D should have a volume of 125% of the surface accumulator volume) plus a pump upgrade (which per API 16D should be able to charge the system within 15 minutes).

HPU RESERVOIR	BSEE Proposed	Pacific Zonda existing	Additional Requirements to meet BSEE proposal
Minimum useable capacity of mixed tank	1,200 USG	1.090 USG	110 USG
Minimum useable capacity of soluble oil tank	605 USG	495 USG	110 USG
Minimum useable volume of glycol tank	550 USG	440 USG	110 USG
Total stored fluid volume	750.28 USG	607.89 USG	142.39 USG
Total stored fluid volume	750.28 USG	607.89 USG	142.39 USG

The real-estate and weight requirements for this magnitude of upgrade will be problematic as the BOP control rooms are built around the equipment.

PACIFIC DRILLING SUGGESTED TEXT:

250.735 (a) The surface accumulator system must meet the requirements of API 16D 5.2.3.1 (The hydraulic control system for a subsea BOP stack shall have a minimum total usable power fluid volume, with the pumps inoperative, to satisfy the following requirements:

a. A minimum FVR (Functional Volume Requirement) of one hundred percent (100%) of the power fluid volume required to open and close, at zero (0) wellbore pressure, the ram BOPs (to a maximum of four (4) ram BOPs having the least cumulative operating volume requirements) and one (1) annular BOP in the BOP stack, based on the annular BOP with the larger volume requirement.

The fluid volume required for BOP ram locking, if provided, shall be included in this volumetric requirement. The volume design factor shall be determined by the sizing calculation method selected per 4.2.3.1. For pilot functions not directly related to the operation of the minimum required BOP or diverter functions, the manufacturer shall determine the needed FVR.

b. The pressure of the remaining accumulator volume after opening and closing four (4) of the ram BOPs and one annular BOP including the volume design factor for pressure limited discharge the selected calculation method, shall exceed the calculated minimum system operating pressure. The calculated minimum system operation pressure shall exceed the greater of the following:

1. The minimum calculated operating pressure required (using the closing ratio) to close any ram BOP (excluding shearing pipe) at the maximum rated wellbore pressure of the BOP stack.
2. The minimum calculated operating pressure required to open and hold open any choke or kill valve in the stack at the maximum rated wellbore pressure of the BOP stack.
3. The normal minimum recommended closing pressure for the annular preventer, closing on the smallest diameter tubular in the string.

PACIFIC DRILLING ECONOMICS

50 x 15 USG accumulators plus piping, valves and installation will cost in the region of $600,000.

Tank modifications are estimated at $200,000 per rig.

-----0-----

250.735 (b) An automatic backup to the primary accumulator-charging system. The power source must be independent from the power source for the primary accumulator-charging system. The independent power source must possess sufficient capability to close and hold closed all BOP components under MASP conditions as defined for the operation;

PACIFIC DRILLING COMMENT
There is no need to reinvent the wheel.

PACIFIC DRILLING SUGGESTED TEXT:
250.735 (b) The accumulator charging system must meet the requirements of API 16D 5.2.2.1 Pump Systems. (The manifold pumping unit provides power fluid for all of the control system hydraulic functions. The same pumping unit may be used to provide fluid power for the control of both the BOP and diverter system. The manifold pumping unit shall comprise a minimum of two (2) pump systems with at least two independent power systems. The cumulative output capacity of the pump systems shall be sufficient to charge the entire accumulator system from precharge pressure to the system rated working pressure within 15 min. With the loss of one pump system or one power system, the remaining pump systems shall have the capacity to charge the entire accumulator system from precharge pressure to the system rated working pressure within 30 min.
An independent power supply is a source of power that is not impaired by any fault which disables the power to the other pump system(s). Examples of independent power supplies:
1. One pump may be powered from the emergency buss on an all-electric power rig.)
2. On electric drive rigs, separate electric motors and motor controllers constitute independent power supplies providing they are fed from separate busses or from busses that can be isolated by means of a buss tie circuit breaker.
3. Compressed air is not considered an independent power supply unless the compressor is powered by a different prime mover, or the electric motors for compressors is powered by a system which is independent from the primary electrical supply.

-----0-----

250.737 What are the BOP system testing requirements?

Your BOP system (this includes the choke manifold, kelly valves, inside BOP, and drill string safety valve) must meet the following testing requirements:

250.737 (a) Pressure test frequency. You must pressure test your BOP system:

(1) When installed;

(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;

(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 14 days (or 30 days for blind-shear rams). You must indicate in your APD which casing strings and liners meet these criteria;

(4) The District Manager may require more frequent testing if conditions or your BOP performance warrants.

PACIFIC DRILLING COMMENT:
250.737(2) and (3) API S53 and the international community follow a 21 day pressure test cycle for BOP stacks. To keep it simple why do we not include the shear rams into the same test schedule?
Various studies, including the Blow-out Prevention Equipment Reliability Joint Industry Project (Phase I – Subsea) from 15 January 2010 commissioned by MMS, and, BOP Reliability, Availability and Maintainability Analyses for BSEE from June 2013, have shown that the majority of BOP and BOP control issues are discovered during a function, rather than a pressure, test. The data behind these reports support the increased time between pressure tests but also keeping the function test on a seven day cycle.

PACIFIC DRILLING SUGGESTED TEXT:
Your BOP system (this includes the choke manifold and drill string valves) must meet the following testing requirements:
250.737 (a) Pressure test frequency. You must pressure test your BOP system:
(1) When installed;
(2) Before 21 days have elapsed since your last BOP pressure test. You must begin to test your BOP system before midnight on the 21st day following the conclusion of the previous test;
(3) Before drilling out each string of casing or a liner. You may omit this pressure test requirement if you did not remove the BOP stack to run the casing string or liner, the required BOP test pressures for the next section of the hole are not greater than the test pressures for the previous BOP test, and the time elapsed between tests has not exceeded 21 days. You must indicate in your APD which casing strings and liners meet these criteria;
(4) The District Manager may require more frequent testing if conditions or your BOP performance warrants.

-----0-----

250.737 (b) (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 rated working pressure of the equipment or be 500 psi greater than your calculated MASP, as 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.

PACIFIC DRILLING COMMENT:
It seems as if the words 'lesser of the' are missing from this section.
Hydrostatic pressure should also be accounted for in subsea tests by deducting this from the surface applied pressure. The pressure differential of the BOP stack cannot exceed the rated working pressure (RWP) of the BOP.
The Driller's Control Panel is preferred for conducting the subsea pressure tests as it is the best location for monitoring the well during the test.

PACIFIC DRILLING SUGGESTED TEXT:
250.737 (b) (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 (hydrostatic pressure plus the surface applied) high-pressure test must equal the lessor of the rated working pressure of the equipment or be 500 psi greater than your calculated MAWHP, as defined for the operation for the applicable section of hole. Before you may test BOP equipment to the MAWHP plus 500 psi, the District Manager must have approved those test pressures in your APD.

-----0-----

250.737 (b) (3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP.
The high pressure test must equal 70 percent of the rated working pressure of the equipment or be 500 psi greater than your calculated MASP, as 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.

PACIFIC DRILLING COMMENT:
It seems as if the words 'lesser of the' are missing from this section.
Hydrostatic pressure should also be accounted for in subsea tests by deducting this from the surface applied pressure. The pressure differential of the BOP stack cannot exceed the rated working pressure (RWP) of the BOP.
The Driller's Control Panel is preferred for conducting the subsea pressure tests as it is the best location for monitoring the well during the test.

PACIFIC DRILLING SUGGESTED TEXT:
250.737 (b) (3) High-pressure test for annular-type BOPs, inside of choke or kill valves (and annular gas bleed valves for subsea BOP) above the uppermost ram BOP.
The (hydrostatic pressure plus the surface applied) high pressure test must equal the lesser of 70 percent of the rated working pressure of the equipment or 500 psi greater than your calculated MAWHP, as defined for the operation for the applicable section of hole.
Before you may test BOP equipment to the MAWHP plus 500 psi, the District Manager must have approved those test pressures in your APD.

-----0-----

250.737 (c) Duration of pressure test. Each test must hold the required pressure for 5 minutes, which must be recorded on a chart not exceeding 4 hours. However, for surface BOP systems and surface equipment of a subsea BOP system, a 3- minute test duration is acceptable if recorded on a chart not exceeding 4 hours, or on a digital recorder. The recorded test pressures must be within the middle half of the chart range, i.e., cannot be within the lower or upper one-fourth of the chart range. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

PACIFIC DRILLING COMMENT:
The pressure testing regimes are clearly defined in API S53.

PACIFIC DRILLING SUGGESTED TEXT:
250.737 (c) Duration of pressure test. The high pressure subsea test should be stable for at least five-minutes. Test pressure gauges, 4-hour chart recorders, and/or data acquisition systems shall be used and all testing results shall be recorded. Analog test pressure measurements shall be made at not less than 25% and not more than 75% of the full pressure span. If the equipment does not hold the required pressure during a test, you must correct the problem and retest the affected component(s).

-----0-----

250.737 (d) (4) Perform an initial subsea BOP test.
(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.

PACIFIC DRILLING COMMENT:
There is no acknowledgement of the difference between the initial subsea tests and the subsequent subsea tests. The Driller's Control Panel is preferred for conducting the subsea pressure tests as it is the best location for monitoring the well during the test.

PACIFIC DRILLING SUGGESTED TEXT:
250.737 (d) (4) Perform a pre-deployment test before running the subsea stack
(i) Perform an initial subsea BOP test upon landing on the wellhead.
(ii) You must perform the subsequent subsea tests at intervals of no more than 21 days from the initial subsea test.
(iii) You must submit test procedures with your APD or APM for District Manager approval.
(iv) You must pressure test well-control rams according to (b) and (c) of this section.

-----0-----

250.737 (d) (5) Alternate tests between control stations and pods.
(i) For two complete BOP control stations:
(A) Designate a primary and secondary station, and both stations must be function-tested weekly,
(B) The control station used for the pressure test must be alternated between pressure tests, and
(C) For a subsea BOP, the pods must be rotated between control stations during weekly function testing, and the pod used for pressure testing must be alternated between pressure tests.
(ii) Any additional control stations must be function tested every 14 days.

PACIFIC DRILLING COMMENT:
There is no acknowledgement of the difference between the initial subsea tests and the subsequent subsea tests.
Although the function tests should alternate between the panels the stack pressure test is best functioned from the Driller's Control Panel as that location is best for monitoring the well during the test.

PACIFIC DRILLING SUGGESTED TEXT:
250.737 (d) (5) All well control components (excluding hydraulic connectors and shear rams) of the BOP stack shall be function tested to verify the components intended operations at least once every seven days, or as operations allow. Pressure tests qualify as function tests. Casing shear and blind shear rams shall be function tested at least once every 21 days.
Prior to deployment, all BOP control stations and both pods shall be function tested. The operability of individual control stations shall be tested.
Subsequent function tests shall be performed from one BOP control panel and one pod weekly. These tests shall rotate through both pods and both main panels.
The Driller's Control Panel is preferred for conducting the subsea pressure tests as it is the best location for monitoring the well during the test.

-----0-----

250.737 (d) (10) Function test blind-shear ram BOPs every 14 days.

PACIFIC DRILLING COMMENT:
The shear rams are the last resort and should be functioned just frequently enough to give us confidence that they will be available for use when required. If it is accepted to change the BOP stack pressure test regimen to a 21 day cycle then we should include the shear rams within that cycle and this will keep it to a minimum.

PACIFIC DRILLING SUGGESTED TEXT
250.737 (d) (10) Function test blind-shear ram BOPs every 21 days.

-----0-----

250.737 (d) (13) Function test autoshear, deadman, and EDS systems separately on your subsea BOP stack during the stump test. The District Manager may require additional testing of the emergency systems. You must also test the deadman system and verify closure of the shearing rams during the initial test on the seafloor.

250.737 (d) (13) (v) For the function test of the deadman system during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.

PACIFIC DRILLING COMMENT:
The NOV system uses an Emergency Hydraulic Backup System to fulfill all requisites of both 'Deadman' and 'Autoshear' systems. With this in mind the Deadman system tests all functions and features required for both systems and therefore one test covers both systems. It is not necessary to individually test both.
If a rig has the ability to simulate the deadman test on the wellhead, and they have tested the sequence on surface, then they should do so as this is much less of a risk than carrying out a 'live' test.

PACIFIC DRILLING SUGGESTED TEXT
250.737 (d) (13) Function all emergency BOP control systems on your subsea BOP stack during the pre-deployment (stump) test. The District Manager may require additional testing of the emergency systems. You must also test the deadman sequence and verify closure of the shearing rams during the initial test on the seafloor.

-----0-----

PACIFIC DRILLING SUGGESTED TEXT
250.737 (d) (13) (v) If the deadman sequence was successfully tested on surface before deploying the BOP stack, and then a simulated test on the wellhead is sufficient. If a simulated test is not possible then for the test of the deadman sequence during the initial test on the seafloor, you must have the ability to quickly disconnect the LMRP should the rig experience a loss of station-keeping event. You must include your quick-disconnect procedures with your deadman test procedures.

-----0-----

250.739 What are the BOP maintenance and inspection requirements?

250.739 (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 not be performed in phased intervals. A BSEE-approved verification organization is required to be present during the inspection and must compile a detailed report documenting the inspection, including descriptions of any problems and how they were corrected. You must make this report available to BSEE upon request.

PACIFIC DRILLING COMMENT:
There is no reasonable logic in requiring a complete breakdown and detailed physical inspection of the BOP and every associated system and component to be performed all at one time every five years. To try and perform such an inspection could take almost a year. The staggering of the inspections, as we currently do (continuous machinery survey), allows the equipment owner to keep most major inspection and maintenance off the 'critical path', to improve available up-time and reduce the quantity of fleet spares required for each rig.
There are major infrastructure obstacles in trying to conduct a full inspection at one time; the GoM is limited in how many floating cranes are available, the OEMs only have a limited amount of facilities available for any necessary remanufacturing, the stocks of spare parts, by the OEMs, would have to be greatly increased, third party NDE companies would struggle to keep all of the contractors supplied, etc.
As in existing continuous machinery survey scenarios, on-board inspections shall be performed by a competent person(s) witnessed and documented by either a licensed Chief Engineer or a competent third party.
If we were to carry out the entire inspection at one time then we would essentially have to conduct a full commissioning exercise afterwards and we would be trying to get all of the third parties to assemble their paperwork for this massive exercise all at one time. Our experience tells us that these latter two exercises would almost double the time required for the inspection itself.
The vagueness of 'every associated system and component' will also prevent auditable compliance.
Would a major component replaced one well before such an event require re-inspection?

PACIFIC DRILLING SUGGESTED TEXT
250.739 (b) At least every five (5) years, the well control system components shall be inspected for repair or remanufacturing in accordance with the equipment owner's PM program and manufacturer's guidelines. Individual components may be inspected on a staggered schedule.
As an alternative to a schedule-based inspection program, a rig-specific inspection frequency can vary from this 5 year interval if the equipment owner collects and analyzes condition based data (including performance data) to justify a different frequency. This alternative may include dynamic vs. static seals, corrosion resistant alloy inlays in sealing surfaces, resilient vs. metal to metal seals, replaceable wear plates, etc.
For schedule and condition based inspection programs, certain equipment shall undergo a critical inspection (internal/external visual, dimensional, NDE, etc.) annually, or upon recovery if exceeding 1 year: e.g. shear blades, bonnet bolts (or other bonnet/door locking devices), ram shaft button/foot,

welded hubs, ram cavities and ram blocks. The actual dimensions shall be verified against the manufacturer's allowable tolerances.
Inspections shall be performed by a competent person(s) witnessed and documented by either a licensed Chief Engineer or a competent third party.
Consider replacing elastomeric components and checking surface finishes for wear and corrosion during these inspections.
Documentation of all repairs and remanufacturing shall be maintained in accordance with API S53 7.6.10.

These inspections shall be documented and made available to BSEE District Manager upon request.

PACIFIC DRILLING ECONOMICS

From our peers we have two actual examples; one for a contractor that brought the ship to quayside and exchanged one stack for another: $13 million for the yard costs, 73 days out of service and +/- $40 million for the replacement stack. (Using the BSEE daily operating cost of $1MM per day, this equates to $126MM **plus the material costs**).

The second example brought a ship to quayside and completed the inspection, maintenance and repairs to the existing equipment. This consumed a total of 257 days for the stack and choke manifold. (Using the BSEE daily operating cost of $1MM per day, this equates to $257MM **plus the labour and material costs**).

The average of the two methods is $191,500,000 per stack ($38.3MM per stack per year) plus labour and materials, and many rigs have two complete BOP stacks.

This statement highlights common perception which unfortunately is widespread.

It is close to impossible to remove a BOP stack from a rig in ten days, let alone replace one. The 67 days mentioned above is realistic for the time it takes to remove a stack from a rig and then install a new stack ($40 million at 2011 prices) on the rig taking into account the realistic time to make adjustments to the handling and storage equipment, the commissioning time for the handling and control equipment and then carrying out the full testing regime.

The actual five year inspection of the equipment carried out at one time will take close to the 257 days shown in the second example above and that is for one BOP stack.

If regulation states that we all have to do this then the OEM facilities will quickly create a backlog extending this even longer. There are only a few crane barges in the GOM capable of lifting a complete BOP stack from a rig in one piece and of the OEMs, only Cameron have a facility on the water in the GOM that could ship or receive a fully tested and commissioned BOP stack in one piece. We do not currently own any Cameron equipment.

Because of the time it takes any of the OEMs to build, test and deliver a BOP stack it is, in fact, unusual for any two to be exactly the same. This makes the concept of having a spare stack between several rigs a bit of a fantasy. In reality we have spare BOPs, connectors and valves which we can (currently) share, but if the entire BOP stack has to be inspected and maintained at one time then this equipment will be useless to us.

-----0-----

250.739 (d) You must ensure that all personnel maintaining, inspecting, or repairing BOPs, or critical components of the BOP system, meet the qualification and training criteria specified by the OEMs and recognized engineering practices.

PACIFIC DRILLING COMMENT:
The BOP equipment OEMs do not publish and qualification or training criteria for their personnel. Our subsea personnel are competent for their positions and have all undergone specific BOP and BOP control system operation and maintenance training by both the OEMs and some specialist training companies.

PACIFIC DRILLING SUGGESTED TEXT
250.739 (d) would require that the personnel, who maintain, inspect, or repair BOPs or other critical components meet the qualifications and training criteria specified by the equipment owner and that such maintenance, inspection, and repair be undertaken in accordance with API S53.

-----0-----

Comments on 'Recommendations on BOPs' (Page 21508)

Each of the previously discussed investigations resulted in reports that contained recommendations to improve offshore safety. One consistent element in each of the investigations was the recognition that additional requirements related to BOPs and well-control equipment are needed. The following list contains some of the recommendations on BOPs and related equipment from the various investigations:

—The BSEE should consider promulgating regulations that require operators/contractors to have the capability to monitor the subsea electronic module (SEM) battery(ies) from the drilling rig, to ensure that there is sufficient battery power to operate the system.

PACIFIC DRILLING COMMENT:
SEM batteries are only in Cameron control systems. A better approach, in our opinion, would be to state that all batteries within subsea components of the BOP control systems that can affect the operation of the equipment must be continuously monitored from the drilling rig, to ensure that there is sufficient battery power to operate the system.

--0--

—The BSEE should consider requiring standardization of: Remotely Operated Vehicle (ROV) intervention panels, ROV intervention capabilities, and maximum closing times when using an ROV; ROV hot stab and receptacles per API RP 17H; and hot stab designs between drilling and production operations.

PACIFIC DRILLING COMMENT:
API Standard 53, which is incorporated by reference, already includes:
7.4.16.1.3 All critical functions shall be fitted with single-port docking receptacles designed in accordance with API 17H.
7.4.16.1.6 All critical functions shall meet the closing time requirements in 7.4.6.5.4
7.4.6.5.4 The following individual response times shall be met by at least one of the surface/subsea power supplies:
a) close each ram BOP in 45 seconds or less;
b) close each annular BOP in 60 seconds or less;
c) unlatch the riser (LMRP) connector in 45 seconds or less;
d) response time for choke and kill valves (either open or close) shall not exceed the minimum observed ram close response time.

--0—

—The BSEE should consider requiring a blind-shear ram design that incorporates improved pipe-centering in the shear ram.

PACIFIC DRILLING COMMENT:
This focus could stifle future designs and improvements. It would be better to state that the shear rams must be able to shear the pipe in, or from, any position within the wellbore.

--0--

—The BSEE should make effective use of industry standards and best practice guidelines used by other countries with the recognition that standards need to be updated and revised continually.

PACIFIC DRILLING COMMENT:
Agreed.

--0--

—The BSEE should improve reporting of safety-related incidents and require the reporting of near-misses to assist in accident prevention and to improve standards.

PACIFIC DRILLING COMMENT:
All safety related incidents should be reported.

--0--

—The BSEE should develop standardized requirements for the training and certification of key industry personnel.

PACIFIC DRILLING COMMENT:
IADC have worked with the drilling contractors to develop competency standards.

--0--

—The BSEE should rely on independent organizations to verify and certify compliance with critical designs and required processes.

PACIFIC DRILLING COMMENT:
The equipment is designed and manufactured before we select it. Design and operation are two very separated issues. When the BSEE approves an organization they are approving the decisions of that organization and therefore retain responsibility for their decisions.
It is unusual to find somebody qualified in both design specifications (such as API 6A, 16A and 16D) who is also intimately familiar with operating standards (such as API S53)

--0--

—The BSEE should ensure that the general well design includes a review of fitness of the components for the intended use.

PACIFIC DRILLING COMMENT:
It seems as if there is a perception that we design BOP stacks for individual wells, when in reality an operator will contract a rig based on the equipment that is already installed on that rig. API S53 7.1.2 lists the standard BOP Stack Classifications that we currently use.

--0--

—The BSEE should consider promulgating regulations that would require operators to report leaks associated with BOP control systems.

PACIFIC DRILLING COMMENT:
The 'Group of Seven' drilling contractors are already reporting all failures, which includes leaks, to a common database. Discussions are ongoing to expand this across the industry.

--0--

—The BSEE should consider promulgating regulations that would require real-time, remote capture of drilling data and BOP function data.

PACIFIC DRILLING COMMENT:
The capture of safety and environmental related information from rig systems and the transmittal of such information to shore is good for troubleshooting assistance, training or investigation type follow up purposes, but it should not be considered for any kind of

control. The people who have the situational awareness to understand exactly what is happening are already on board the rig and they retain responsibility for their rig. Lack of available cyber security could cause unwanted interference if data needs to be forwarded real time. Interference might be the unexpected operation of equipment creating additional hazards, or instrumentation displaying incorrect information causing incorrect hazardous actions.

--0--

—The BSEE should require improvement of the instrumentation on BOP systems so that the functionality and condition of the BOP can be monitored continuously.

PACIFIC DRILLING COMMENT:
Instrumentation is improving almost daily, but we need to clearly state what information gathering from the BOP control system rewards us sufficiently to counter the risk of making the system more complicated. It also needs to be highlighted that the direct and discrete hydraulically operated systems are very limited in what they can provide anyway.

--0--

—The BSEE should consider regulations that address a reasonable margin of safety between the ECD and the pressure that would cause wellbore fracturing.

PACIFIC DRILLING COMMENT:
Beware of unintended consequences. If 'reasonable' means a large number then this will mean that many deepwater wells cannot be drilled. The reasonable margin should be formalized as what is todays good oilfield practice, unless MPD or DGD equipment is installed for which other margins are applicable.

--0--

—The BSEE should establish testing and maintenance requirements for BOPs to ensure operability and increased reliability appropriate to the environment and application.

PACIFIC DRILLING COMMENT:
Make API S 53 mandatory. Thousands of man-hours from industry SMEs (Subject Matter Experts) and BSEE representatives went into the writing of API S53, incorporated by reference, which lists the already accepted and followed test criteria in API S53 7.6.5 and the periodic maintenance and inspection criteria in API S53 7.6.9.3.

--0--

—The BSEE should require improvement of the design capabilities of the BOP systems so that they can shear and seal all combinations of pipe under all possible conditions of load from the

pipe and from the well flow, and so that there would always be a shearable section of the drill pipe in front of a blind-shear ram in the BOP.

PACIFIC DRILLING COMMENT:
This is a goal that will not be achieved overnight. To have this with a 7 – 10 year target is good.

--0--

—The BSEE should require demonstration of the performance of the design capabilities of BOPs and require that they be independently certified on a regular basis by test or other means.

PACIFIC DRILLING COMMENT:
We believe that this was meant to state that 'The BSEE should require demonstration that the performance of the BOPs still meets the original design capabilities, and require that they be independently certified on a regular basis by test or other means.

The 'independence' of a third party employed by the owner of the equipment is another topic that needs to be discussed.

--0--