October 2, 2015

Director Brian Salerno
Bureau of Safety and Environmental Enforcement
U.S. Department of the Interior
1849 C Street, NW
Washington, DC 20240

Re: Blowout Preventer Systems and Well Control

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

Dear Director Salerno:

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 appreciate the opportunity to meet with you and your staff on September 14, 2015, to further discuss some our concerns with the proposed regulatory changes to Blowout Prevention Systems and Well Control requirements in 30 C.F.R. part 250. We have attached our summary and minutes from the meeting for your records.

As the meeting showed, due to lack of time, there are still discussions and clarifications needed on the proposed rule, including understanding the specific risk BSEE is trying to address in order to enable development of rules that are both workable and effective, and to avoid unintended consequences that increase risk.

While we appreciate the opportunity to meet on September 14 and agree that it was a good start, we ask BSEE consider our initial request to engage in technical workshops with each of the eight industry workgroups that have analyzed the respective sections of the proposed rule. Such workshops would be the most efficient method of developing final regulations that address the existing fundamental technical and economic flaws in the proposed rule, and allow constructive development of rules that promote safety and protection of the environment, as well as, economic growth, innovation, competitiveness and job creation. To expedite these workshops, these trades associations are volunteering to set up and facilitate these discussions as soon as possible. We will arrange a one day workshop with 8 breakout sessions (drilling margins, real time monitoring, casing and cementing, BOP equipment, containment, inspection and mechanical integrity, API standards, and economic analysis) on a date and location of your choosing. Please let us know when and where you would like us to set up these workshops.

In the absence of such workshops, it is imperative to still continue dialogue on the following topics:

- Drilling Margins
- BOP equipment requirements that exceed API 53
- Real Time Monitoring
- Cementing and Packer Fluid Requirements

In addition to the topics listed above, we also need to resolve the vast difference between the BSEE economic analysis of this proposed rule and the third party and Industry analyses. We also encourage BSEE to closely examine the use of absolute language used throughout the proposed rule such as the use of words like “any” and “all” which can create unintended burden and confusion during implementation due to varying interpretations. We are available at your earliest convenience to continue these discussions.

During the meeting on September 14, Industry again reiterated our commitment to create a Joint Regulatory and Industry work group focused on collecting information regarding historical events for use in the development of guidelines for the design and qualification of BOP equipment under flowing conditions. The Steering Committee for this workgroup has been formed and will be holding the first Steering Committee Meeting Tuesday, October 6, 2015. Following the Steering Committee meeting and agreement on the scope and parameters of the workgroup, invitations will be sent to BSEE and the Industry at large to form the full workgroup.

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, working together we can develop practical final rules that are ultimately both workable and effective. We look forward to receiving a date and location from you to continue these discussions.

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: Dan Utech, Deputy Assistant to the President for Energy and Climate Change
Deputy Secretary, Michael Connor
Chief of Staff, Tommy Beaudreau
Assistant Secretary Land and Minerals Management, Janice Schneider
Chief Office of Offshore Regulatory Programs, BSEE Doug Morris

Attachment

Attachment

JOINT TRADE ASSOCIATIONS WCR MEETING WITH BSEE
SEPTEMBER 14, 2015
12:00 – 1:30 PM Eastern
Main Interior Building, 1849 C Street, NW, Room 3447, Washington, DC 20240

Industry Attendees

1. Holly Hopkins, API
2. Alan Spackman, IADC
3. Sandi Fury, Chevron
4. Rick Graff, Chevron
5. Chris Stewart, ENSCO
6. Matt Givens, Cameron
7. Pete Bennett, Pacific Drilling
8. Tony Hogg, Pacific Drilling
9. Lisa Grant, Noble Energy
10. Tim Woods, XOM
11. Paul Schuberth, XOM
12. Ken Armagost, APC
13. Pat Watson, APC
14. Todd Durkee, APC
15. Andy Reed, BHP Billiton
16. Jim Grant, BP
17. Ken Dupal, Shell

BSEE Attendees

1. Doug Morris, Chief, Office of Offshore Regulatory Programs
2. Lakeisha Harrison, Chief, Regulations and Standards Branch
3. Kirk Malstrom, Regulations Development Section
4. Jarvis Outlaw, Houston
5. Fred Brink, GOMR
6. Dave Trocquet, GOMR
7. Mike Farber, Senior Advisor to the Director
8. Steve Payson, BSEE Economist
9. Matt Ballenger, SOL
10. Michaela Noble, ASLM

Meeting Minutes

Doug Morris called the meeting to order and indicated a hard stop at 1:30 pm. Introductions were made around the room and BSEE requested business cards from all Industry attendees for the record. Matt Ballenger with the Department's Solicitor's office (SOL) outlined the ground rules for the meeting to comply with the Administrative Procedure Act (APA).

Holly Hopkins opened the meeting from the Industry side with the following remarks:
API, IADC, IPAA, NOIA, OOC, PESA and the US O&G Association appreciate the opportunity to meet with you today to further discuss the Well Control Rule. While we feel it would be most efficient for BSEE to arrange workshops with each of the eight industry workgroups that have analyzed the respective sections of the proposed rule in order to clarify the intent, reach mutual understanding of the proposal, to address fundamental technical and economic flaws in the proposed rule, and allow constructive development of rules that promote safety and protection of the environment, as well as, economic growth, innovation, competitiveness and job creation, this is a step in the right direction.

Holly then asked Pete Bennett to reply to the BSEE's questions on Surface accumulator system 250.735(a).

BSEE Question: Any recommended text for 250.735(a)?

Industry Response:
The industry proposes deleting 250.735(a), and there is no recommended replacement text. The industry accepts and encourages the proposed WCR text to incorporate API 53 by reference.

Many mobile offshore drilling units (MODUs) do not have available space to install the prescribed additional surface BOP accumulator bottles that would be required. In all cases, the additional required associated equipment (e.g., larger fluid reservoir, additional pumps, additional accumulator bottles, etc.) would be problematic in their demands for space and contribution to additional complexity of rig systems. The need for such equipment has not been justified and industry sees no safety benefit as API 53 already demands sufficient volume to close multiple BOPS, above and beyond the minimum required in a well control event.

BSEE Question: How long would it take to come into compliance with these surface accumulator requirements?

Industry Response:
The majority of the industry already complies with the API 53 drawdown test requirements in sections 6.5.6.2 and 7.6.8.2. For those who do not, at least 1 year after publication of the final rule would be required.

If BSEE is asking about industry's ability to meet the text of the proposed WCR then more clarifications are needed to understand the intent and what is actually required. As currently written the proposed WCR is ambiguous and may be interpreted differently than as intended. Compliance with the proposed requirements would take at least 5 years from publication of the final rule.

BSEE Question: What would be the industry costs associated with recommended text?

Industry Response:
The majority of the industry already complies with the API 53 drawdown test requirements in sections 6.5.6.2 and 7.6.8.2. For those who do not, a representative cost would be approximately $1M per rig but this would vary on a case-by-case basis.

Additional discussion and clarification occurred regarding the estimated costs.

Holly then asked Chris Stewart to reply to the BSEE's question on Hydraulic locks on surface BOPs 250.735(g).

BSEE Question: What is the rationale for allowing surface stacks to have manual locks instead of hydraulic locks?

Industry Response:
Manual locks have been used reliably for many years without any safety incidents. The need for hydraulic locks was driven by the application of a subsea BOP which doesn't lend itself to manual locks as it is physically located subsea. The concern was not with having people in the vicinity of the BOP but rather the subsea application required remote locking devices.

During the latest revision of API 53, there was insufficient data (i.e., no recorded incidents where the ram type BOP's were opened under pressure) to require the use of hydraulic locks on surface BOPs. In certain circumstances use of hydraulic locks on surface BOPs is not achievable due to facility space and loading limitations, e.g. platforms, TLPs, and SPARs.

Furthermore, manual locks are more reliable than hydraulic locks due to their simplified design and inherent manual operation (i.e., they do not need hydraulic systems to support their operation).

Operating the equipment under high pressure is routinely done using safe systems of work procedures without incident. Moreover, other equipment is still used with manual functions such as the high pressure choke manifold. Manual chokes and valves are standard components installed on all choke manifolds. Given this, adding remote locks to surface BOPs will not remove personnel from high pressure areas and therefore should not be required.

Holly then asked Matt Givens to reply to BSEE's questions on Sealing under flowing conditions 250.730(a).

BSEE Question: How would this be defined in the APD?

Industry Response:
The APD lists the Maximum Anticipated Wellhead Pressure (MAWHP) as the known conditions of the wellbore. Additionally, the selected and operated BOP system has a known closing ratio and a maximum rated working pressure greater than or equal to the known MAWHP requirements. As part of the BOP System selection and use protocols, the BOP Control System operating pressure and regulator set points will be adjusted to ensure the BOP system is capable of providing the closing force needed to affect a seal against the MAWHP.

During operation, even in flowing conditions, the wellbore pressure does not instantly rise to the MAWHP and instead requires some period of time to reach a state where the pressure begins to have an effect on the functioning of the Annular and Ram BOPs. Observation of well conditions during operation and early detection will allow the BOP System to be functioned prior to exceeding the capability of the BOP.

As a result of this, the MAWHP should be considered as the most anticipated conditions for select, install, maintain, inspect, test, and use rather than an "extreme" or "absolute worst case" event such as flowing conditions that will vary by location and well.

BSEE Question: Regarding the Flowing Conditions workgroup, how do you plan on achieving this goal?

Industry Response:
Historical evidence exists to show the capability to successfully close in and seal the wellbore under flowing conditions. Unfortunately, the well conditions in these historical events are not public knowledge at this time.

The intent would be the creation of a Joint Regulatory and Industry work group focused on collecting information regarding historical events for use in the development of guidelines for the design and qualification of BOP equipment under flowing conditions. These requirements could then be placed in

Industry Specifications and/or the APD. Examples of these collaborative efforts are the creation of API 53 and the recent Joint Industry Task Force on Shearing.

Additional discussion and clarification occurred regarding the "anticipated flowing conditions" referenced in the Industry comment letter. BSEE also asked how long it would take to set up this workgroup and receive the final information. Industry committed to establishing a workgroup.

Holly then asked Rick Graff to reply to BSEE's questions on Safe drilling margin 250.414(c)(2). Rick, Andy Reed and Ken Armagost provided the following information.

BSEE Question: Use of API 92L – Why develop this as a bulletin?

Industry Response:
In response to a request by BSEE in 2012, the offshore industry came together to reach consensus on how to address narrow margin drilling issues specifically related to lost circulation where ECD exceeds the fracture gradient. The document was developed as a white paper, and following the API standard processes, converted to a Bulletin to be included in the WCR discussions. API Bulletins are documents that convey technical information on a specific subject or topic.

88 API documents are IBR by BSEE (broken down as follows):
1 Inspection Code
1 Standard
3 Bulletins
52 Measurement Standards
24 Recommended Practices
7 Product Specifications

BSEE Question: What kind of data would be submitted to BSEE to show the risk assessed safety margin?

Industry Response:
The risk assessment data proposed to be submitted are based on the specific well (local geology, seismic ties, hole conditions, predicted pore pressure, anticipated hydrocarbons present), available contingencies (casing program, mud type), offset wells and historical operational practices. API 92L specifically addresses scenarios of narrow margins and data requirements (i.e., minimum required mud volume, hydrocarbons anticipated, finger print plot, LCM plan).

Adoption of the WCR proposed fixed safe drilling margin would result in Operators using mud weights closer to pore pressure in order to develop reserves in narrow margin environments. This could result in an increase in kicks or wellbore instability issues when drilling, both of which would lead to increased operations integrity risk. Adapting the proposal to accept the use of risk-management in determining drilling margins would enable Operators to run higher mud weights in such scenarios and mitigate these risks. Although the higher mud weights may increase the chance of losses, this is an operational exposure that Industry safely manages on a daily basis and has lower potential consequences (exposure of wellbore fluids to the environment) than kicks. If there is no expected hydrocarbon bearing zone in the hole section, then lost circulation poses minimal-to-no risk for operations.

Operators would be hesitant to sanction a development project without ensuring they could adhere to the proposed prescriptive drilling margin.

Additional discussion and clarification occurred regarding drilling margins. BSEE asked what the acceptable level of risk for BSEE approval should be. Industry provided information to BSEE on this question, including reiterating API 92L as a preferred alternative. Industry is advocating a risk based approach for drilling margins to ensure wells can be engineered to manage the range of anticipated risks without being driven by an arbitrary drilling margin.   As one example, many deepwater wells would be driven to prematurely set contingency casing strings to isolate shallow, non-hydrocarbon bearings zones when margins are less than those in the proposed rules. By contrast, a risk based approach would enable use of existing Industry practices to safely drill these narrow margin intervals and retain contingency strings for deeper intervals. Industry submits to BSEE the APD or APM to define the drilling plan and risk based approach, including contingencies based upon risk assessments.

There was discussion regarding Industry's ability to ask for a departure from the proposed requirement. Industry responded that projects are not planned relying on departure approval and BSEE staff would be less inclined to grant a departure from a regulatory requirement versus operating practice.

In the interest of time, we had to move on to the next topic. It was pointed out to BSEE this is why the Industry has repeatedly asked for more time and more discussion with them. These are complex topics that require detailed discussions, greater than what could be achieved in today's meeting.

Holly asked Tony Hogg to reply to BSEE's questions on 5 year major inspection 250.739(b).

BSEE Question: Allowing for a staggered schedule and possibly a condition based inspection frequency how do you ensure all components are completed?

Industry Response:
- Whether conducting inspection in a staggered schedule or all at once, a tracking tool is used.
- Drilling Contractors have various tracking tools for all well control equipment for each rig. One example is a detailed spreadsheet, which clearly shows the Description, Part Number, Serial Number, the Date of the original COC, the date of all major inspections and a hyperlink to the appropriate documentations. Each line item is automatically color coded to show status. Green is good. Yellow means that we are in the fifth year.
- Anybody can look at the sheet and easily audit any or all line items at any time.

BSEE Question: And done in an appropriate timeframe?

Industry Response:
- This is a function of planning by the individual Rig Managers and their teams and cooperation with the Operators.
- The Rig Manager schedules certain equipment for each Between Well Maintenance period for either an immediate major inspection or replacement by a fleet spare (to allow time consuming work to be carried out offline). The target is, of course, to ensure that we do not see red on the spreadsheet. (Which means something it outside of the 5 year inspection timeframe, overdue for inspection)

BSEE Question: What would be the associated costs with recommended text?

Industry Response:

- This question is a little confusing. The cost of carrying out the five year inspections is an accepted cost of doing business. There is nothing to add because this is what we do now.
- The costs of attempting a complete inspection all at one time is reasonably expected to be more than the replacement costs.

Additional discussion and clarification occurred on this topic. BSEE asked for clarified on whether staggered inspection was current practice, it is. Drilling Contractors have robust systems to inspect and maintain BOPs on a 5 year cycle in compliance with API 53. BSEE asked how they would monitor conditional based inspection. BSEE asked what date should be on the paper work for staggered inspections. Should it be the acceptance date of the equipment from the OEM to the Drilling Contractor? The in service date? Industry responded that the date is only relevant for new equipment which should be the acceptance date and the 5 year cycle begins at that time.

In the interest of time Implementation Timeframes were not discussed in the meeting.

Holly asked Jim Grant to reply to BSEE's questions on RTM §250.724.

BSEE Question: What is the basis to claim the erosion of responsibility and accountability of offshore personnel?

Industry Response:
Based upon industry's reading of the proposed RTM regulation/preamble and comments made by BSEE personnel in RTM workshops, we interpreted the proposed RTM rule as BSEE wanting to potentially limit or remove operational decision making from the offshore personnel and taking those decision-making responsibilities onshore via RTM capabilities or to have BSEE involved in those immediate decision-making operations via a BSEE RTM center.

We feel decision-making for operations should remain with the offshore personnel, particularly in safety and well control events where situational awareness is extremely important and immediate action is required. Generally, operators that use shore-based operations centers do so to assist personnel on the rig with the monitoring of specific functions of the drilling operation, not to assume control of operational activities. Offshore personnel must have full and clear authority for timely safety and well control decision making and are best positioned to manage risk. The basis to claim the erosion of responsibility and accountability of offshore personnel can be highlighted by the following examples of unintended consequences of remote RTM:

- ISO 17969 Guidelines on Competency for Well Operations Personnel - A "second set of eyes" onshore carries a high risk of reducing the "situational awareness" offshore. Remote RTM Oversight carries a very high risk of diluting ownership of rig safety by the rig crew.
- Fundamentals of Naval Weapons Systems, Chapter 20, Command and Control Weapons and Systems Engineering Department, US Naval Academy - "Where high-level commanders possess the capability to engage in evaluation at the on-scene commander level, erosion of authority of the on-scene commander will take place."

BSEE Questions: What cyber security concerns exist, and how are they different from existing communication issues? How are virus or malware introduced, and how is such introduction different from existing communication issues?

Industry Response:
Response to the 2 above questions: Company data systems are highly engineered and segregated systems with multiple firewalls and security protocols to protect them or reduce the likelihood of cybersecurity attacks. As written the rule would require additional access points. Any time an access point is added to the system it increases the potential cybersecurity risks and adds opportunities for malicious or inadvertent virus or malware to be introduced.

Currently the majority of the information that is transferred to RTM systems is not linked to the Drilling Contractors' BOP control system for information but is coming from a segregated monitoring system. The requirement for many of the new data streams would mean access into the Rig Critical Safety systems. There are concerns with this control system access until proven security systems have been put in place. When required connections are established to the drilling contractors control systems they are made intermittently and controlled, not continuous as RTM would be. Existing communication is connected and disconnected as required. RTM implies permanent connection.

Additional discussion and clarification occurred on this topic. An example was discussed of alternative ways different Operators may leverage expertize within their companies to support certain activity phases. In the case of pore pressure prediction, it was highlighted that some Operators may locate experts on the rig while others may be setup to enable expertize to be provided remotely. Either approach can effectively manage operations integrity when the range of risks are assessed and appropriate mitigations put in place, as would be enabled via a Real Time Monitoring Plan requirement. BSEE asked questions regarding the recommendation to have a RTM Plan, specifically, would this plan be submitted and approved. Industry explained that a RTM Plan would be required, but would not be submitted, nor approved, but could be audited for its existence. Similar to a SEMS plan.

Due to time constraints, the following material was not discussed at the meeting but is provided for the record:

In addition, cyber criminals could pose a threat to an offshore drilling rig without taking control of any operating systems. If they are able to access and modify the output of the data that is being monitored, they could create a situation of misinformation. Misinformation in a remotely monitored location (even where remote personnel are additive or supportive) can distract the onsite responsible personnel from the operation and situational awareness that must be maintained.

To ensure RTM can be effective, further discussion is required to understand the specific concerns that BSEE seeks to address with RTM requirements. Associated regulations should be risk-based and enable fit-for-purpose RTM proposals/Plans from individual Operators. As written, the prescriptive requirements are vague and do not provide sufficient detail to enable Operators to understand and assess what the requested minimum requirement is.

BSEE Question: What is the need for new data transmission protocols? Explain?

Industry Response:
Much of the data surrounding BOP heath and potentially other Rig systems are not, in general practice, transmitted in real-time utilizing the WITS transfer protocol. WITS was developed 30 years ago and today's technology transmits significantly more data. Although WITS is a fairly accepted method for transferring well data the additional channels for rig system data that would be required are currently not available. The new channels and measurement type would have to be determined and an update

written, tested and distributed. At a minimum this would require a new release, thus requiring an update of systems utilizing the information. Additionally steps to link current systems to a data conversion to WITS could be required. Redundant sensor data streams are also extremely difficult to archive with the current WITS.

It is possible to update WITS, but implementation for all software is time consuming and not necessarily a straight forward task.

Doug Morris asked if BSEE Economist, Steve Payson, had any questions. Steve asked a series of questions as follows:

- Do the cost estimates from Industry reflect the lowest costs, typical costs or highest costs? API replied that the cost estimates in the Quest Analysis were conservative and by no means the highest costs.
- Regarding the proposed requirements for accumulators bottles, do the cost estimates include:
    - Purchase of equipment
    - Transportation to the well site
    - Installation of equipment
    - Other equipment and structural adjustments?
- In the Quest Analysis:
    - do you have more detailed breakdown of cost estimates
    - breakdown of labor costs vs. equipment costs

Holly Hopkins replied that since no economic questions were provided in advance of the meeting for discussion the Contractors (Quest & Blade) were not asked to attend and volunteered to respond to BSEE's questions if a detailed list was provided.

In the absence of a specific list of questions from BSEE on the Economic Analysis, the following answers to the above are provided:

- The cost estimates in the study represent expected typical costs of the lowest cost solution to overcoming a particular proposed regulation.
- Regarding proposed requirements for accumulator bottles, the cost estimates are limited to purchase and installation of the equipment. Transportation, other potential equipment needed for installation and potential structural changes were excluded as these costs would likely vary significantly on a case by case basis.
- The cost estimates were provided on a requirement by requirement basis. A more detailed break-down from the working data could be provided if requested.
- The study calculated engineer labor costs related to additional direct labor on a requirement by requirement basis, this information could be provided if requested. This would exclude labor elements of equipment, installation, etc.

The allotted time for the meeting expired and Holly Hopkins made the following closing remarks:
Again, thank you for taking the time to meet with us today, in the last five years, we, both the government and industry, have made a continuous effort to enhance safety offshore. Together, we have improved regulations and consensus standards on safety and environmental management systems, and offshore equipment and operations, including well design and well control to protect workers and the environment and ensure designs are robust and equipment operates as expected. While we still need to resolve the vast difference between the BSEE economic impact of this proposed rule and the third

party and Industry analyses, working together we can develop practical final rules that are ultimately both workable and effective. Despite good intentions, the proposed rule adds operational complexity from both an equipment and personal oversight basis. This added complexity can increase rather than decrease risk to personnel and safe project execution. In addition to differences in risk mitigation value, BSEE's estimated costs for the proposed rule are generally very low and the cost-benefit analysis is incorrect by an order of magnitude. The BSEE cost-benefit analysis severely underestimates the actual costs to implement the rule. BSEE estimated the 10-year incremental cost of the rule at approximately $883 million. An independent cost assessment performed by Blade Energy Partners (Blade) and Quest Offshore (Quest) estimated cumulative 10-year costs at approximately $32 billion. We look forward to resolution of these vast differences.