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Comment on BSEE Proposed Rule for Offshore Drilling

Proposal Issued April 2015

4310-VH-P

DEPARTMENT OF THE INTERIOR

Bureau of Safety and Environmental Enforcement

30 CFR Part 250

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RIN 1014–AA11

Oil and Gas and Sulphur Operations in the Outer Continental Shelf—Blowout Preventer Systems and Well Control

Please note that lack of comment on specific sections/paragraphs does not imply acceptance or rejection of an item within the proposed rule – it simply is "lack of comment".

1. Introduction – Overall Goals

The perceived focus of the proposed rule is to minimize the potential for and any and the cumulative flow from an out of control well. This focus can also be summed up in the form of overall goals which are:

A. Prevention of an incident in the 1st place – ensures the safety of the drilling crew & achieves the goal of zero pollution
B. Minimization of the risk x consequence of a blowout

The comment contained here focuses on the 1st goal. However, in doing so, the 2nd goal will also be impacted in a positive way due to minimization of such an event.

The suggestions contained in this comment will significantly reduce the potential for a “blowout event”. The impact on the overall cost of drilling and completing a well will be small. There are some additional costs, but also some opportunity for significant cost savings.

2. Look-back at Macondo

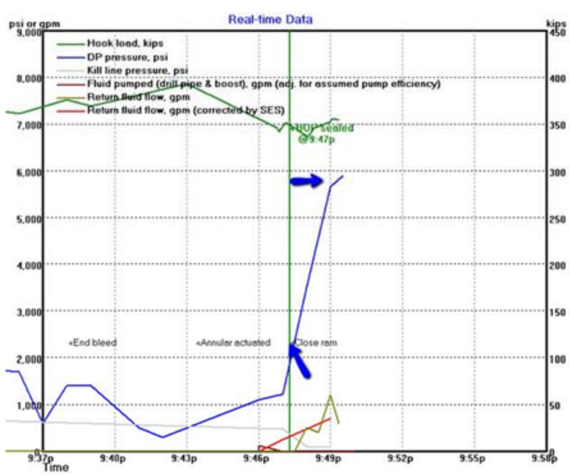
Macondo was a very unfortunate incident. It was completely preventable. Note, most (if not all) other blowouts have also been preventable (particularly if crews had the right equipment, knowledge and training).

The failures at Macondo included (in a “generic” sense):

A. Failure of the barrier system
B. Failure to monitor flow in and out of the well for an extended period
C. Failure to understand (and be able to deal with) the nature of hydrocarbon arrival at surface with zero pressure

It is hard to find another blow-out where one or more of the above was not a primary cause.

The Macondo well itself was shut-in (on VBRs) for a short period of time, prior to the arrival at surface of hydrocarbon (already) in the riser, subsequent explosion and subsequent operation and failure of the shear rams, which negated the shut-in VBRs.



Real-time data evidence from Macondo (CSB report). Starting at 9:47pm, the drill pipe pressure rocketed up from ~1,000 psi to nearly 6,000 psig at ~9:50 pm, when transmission was lost due to the explosion. That high DP pressure can only be explained by a BOP (VBR) sealing. i.e. the well was shut-in at the BOP prior to the explosion

Fig 1 – Macondo Drill Pipe Pressure Record Showing Evidence of Well Shut-in

It seems to be apparent that had there not been hydrocarbon in the riser (and above the subsea BOP) or the hydrocarbon in the riser above the seabed BOP had been handled in an "effective" manner then there would not have been the explosion on the Deepwater Horizon rig and subsequent events would not have happened.

Sadly (and importantly) the crew of the Deepwater Horizon did not have indication of hydrocarbon in the riser and did not have equipment that was best suited to handling such a situation. This remains the case today on many rigs and is not addressed by the proposed rule.

Following the explosion on the Deepwater Horizon rig (and at some time afterwards – unclear as to exactly when), the shear ram(s) were functioned or functioned automatically. It is not clear (to this author) if all conditions that could be imposed on the shutting operation of a shear ram(s) designed to a higher standard than those on the Deepwater Horizon will always result in successful shut-in of a well. In particular, if an explosion occurs at the deck level of a rig it is apparent that personnel may not be able to take any additional actions and it is uncertain if automatic functions will execute (given subsequent extreme flow conditions). In order to ensure a successful outcome, it is essential to put a far greater focus on other parts of the overall drilling and well control system. It is also essential to thoroughly understand how the specific well/rig system will operate (given potential incidents) and communicate this understanding to the rig crew – after all, they are the best line of defense. This focus is detailed below.

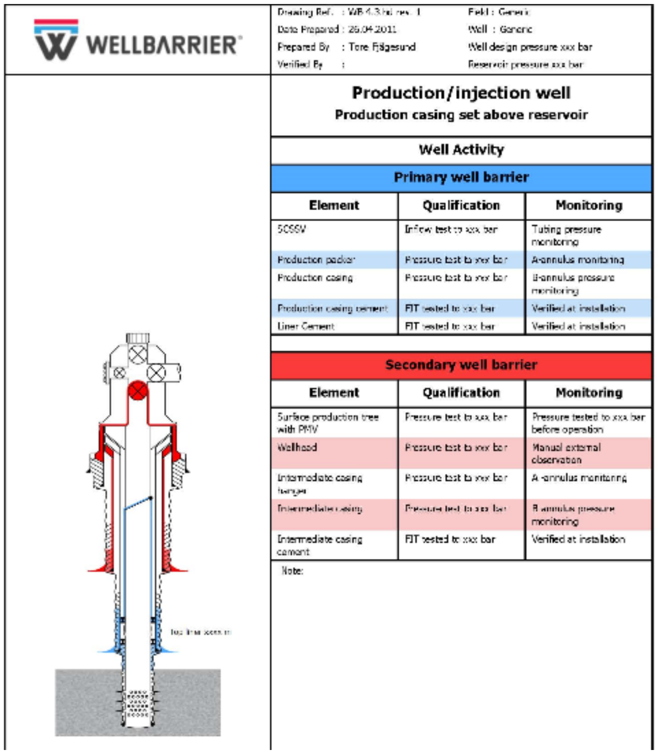
It is suggested that a significant focus be put on the (generic) failures (given as A., B. and C. above) that led to the Macondo incident. Such focus would significantly reduce the risk of a similar incident occurring in the future.

3. Looking Forwards –Minimizing the Risk/Consequences of a Blow-out

Whereas it is important to look back on a specific tragic event, with the goal of preventing a recurrence, it is likely (in oil and gas exploration) that an incident in the future will be different to one in the past due to differences in formations, rig equipment and decisions taken. We must learn from the past, but we must not just focus on preventing a recurrence – the future incident will be different!

With this in mind, it is important to look forwards. It is suggested that the topics shown below are addressed.

1. Whereas it is accepted that **§ 250.462** is an essential element in the overall picture, the requirements and resources devoted to this activity must not take away from the resources devoted to prevention of a blow-out in the first place – perhaps wording to that effect should be included.
2. More focus on the barrier system
    a. A comprehensive (up to date) barrier diagram for each well (Norsok D-010 provides a framework of what can be achieved – **something similar is suggested**), showing the condition and verification of each component of the barrier system is suggested. This diagram must be a central pillar – available for all involved to see and available for inspection by authorities without notice. An example from WellBarrier (www.wellbarrier.com) is given below. It allows the identification of each component of the barrier and the condition/verification of each of these components to be articulated.



WELLBARRIER®

Drawing Ref. : WB 4.3.hl rev. 1
Date Prepared : 26.04.2011
Prepared By : Tore Fjågesund
Verified By :

Field : Generic
Well : Generic
Well design pressure xxx bar
Reservoir pressure xxx bar

Production/injection well

Production casing set above reservoir

Well Activity

Primary well barrier

Element	Qualification	Monitoring
SCSSV	Inflow test to xxx bar	Tubing pressure monitoring
Production packer	Pressure test to xxx bar	A-annulus monitoring
Production casing	Pressure test to xxx bar	B-annulus pressure monitoring
Production casing cement	FIT tested to xxx bar	Verified at installation
Liner Cement	FIT tested to xxx bar	Verified at installation

Secondary well barrier

Element	Qualification	Monitoring
Surface production tree with PMV	Pressure test to xxx bar	Pressure tested to xxx bar before operation
Wellhead	Pressure test to xxx bar	Manual external observation
Intermediate casing hanger	Pressure test to xxx bar	A-annulus monitoring
Intermediate casing	Pressure test to xxx bar	B annulus pressure monitoring
Intermediate casing cement	FIT tested to xxx bar	Verified at installation

Note:

Fig. 2 – Well Barrier Diagram (www.WellBarrier.com)

The goals for a transparent barrier system are:

- Updated barrier diagram available at all times to operations team, management teams, BSEE (and other authorities)
- It will allow anyone within the operations team to question a “mis-interpretation” of the status of a component of the barrier system (perhaps within an effective “Stop Work Program”)
- It will allow management teams to insist upon an upgrade to a barrier (if appropriate) – it also means that such teams are informed as to the condition of the barriers (and are responsible)
- It will allow the effects of prolonged operations on the barrier system (if any), see **§ 250.722** to be captured on a “live” record.
- It will allow BSEE (and others) to quickly assess barrier conditions – it would also be expected that an insufficient/defective barrier is remedied as opposed to be allowed to be on an assessment that is readily available to the authorities! (perhaps an analogy is the New York Restaurant Hygiene Grading System - http://www.nyc.gov/html/doh/downloads/pdf/rii/restaurant-grading-18-month-report.pdf - salmonella poisonings are being reduced!)

b. Improvements (as appropriate) to the barrier system. These will include improvements to BOP equipment (noted in proposed rule - **§ 250.734** is reasonable for new wells – it may be appropriate to allow 4-Ram BOPs to be used (in moored set-up) on some existing wells with older wellheads – the use of heavier/taller BOP stacks may potentially induce higher bending moments that will reduce the overall safety when such a combination is imposed). In addition improvements should be considered to the monitoring and verification of make up/torqueing of casing/tubular connections etc.. For example **§ 250.423 para (c) & § 250.721** may include a requirement to utilize torque/turn evaluation equipment when running production casing and tubing to confirm that thread mating has been according to specification.

   c. For abandonment and isolating zones **§ 250.1715** (and elsewhere where the length of a cement isolation column is noted) it is strongly suggested that the following words are included:

      The lengths of the cement isolation column noted within are absolute minimum lengths and may be subject to questioning with respect to proof of verification. Utilizing longer cement isolation columns will in many cases result in an insignificant increase in operations cost and may result in less arduous barrier verification.

3. Real time data monitoring is essential (and noted in the proposed rule **§ 250.724**).

   Para (b) notes that this data "must be monitored by qualified personnel who must be in continuous contact with rig personnel during operations". This contributor suggests the use of the word "can" to replace "must" in this paragraph. It is suggested that the onshore team NOT be a 24/7 2nd set of eyes, but be a fully informed team with specialist expertise that can back up the offshore team as required. This team will update modeling of potential well conditions, such that adjustments to procedures can be discussed with the operations team. Remotely following an operation on a 24/7 basis (seeing some of what the Driller sees) may not be effective and constantly suggestion/ordering the offshore team to take certain decisions will be very detrimental to the whole operation – an airline does not tell a pilot how to fly the plane!

   Collecting information on the operation/condition of the BOP (perhaps very well represented by the operating characteristic of the BOP control system) is a very positive step. Close monitoring of this control system may be a better indicator that the BOP will work in the future rather than a periodic test (though periodic testing is essential). It is suggested that as this monitoring data is gathered (from all operators/contractors) a correlation is made between indicators contained within this data and subsequent BOP testing, with the potential goal of reducing BOP testing requirements at some time in the future if it can be shown that real time monitoring of the condition of the BOP/BOP control system provides a better indication of future BOP functioning.

   This could allow for more effective BOP operation and significant cost savings.

4. **§ 250.703** focuses on "What must I do to keep wells under control?" In addition to the items noted in this requirement more focus must be placed on minimizing the volume of any influx that occurs such that the influx can be readily dealt with using typical existing BOP equipment, e.g. BOP, choke and kill lines. Better measurement of flow in and out of the well is the key.
   a. Better flow metering (flow meters such as Coriolis should be a given)
   b. Tighter control of pit levels
   c. Better understanding of what differences (if any) could occur between flow in and flow out. This specifically relates to the case where there is hydrocarbon (of some sort) within the flow system. **It is essential that detailed realistic modeling of potential events is undertaken such that potential issues can be recognize**d, mitigations taken and crews

properly (and effectively) trained. **Realistic modeling will enable "what is normal" to be established. It is then much easier for a rig crew to identify "what is not normal".** Training in "general" principles of well control is simply not good enough. There must be training which is based on the well to be drilled (mud to be used (SOBM?) and the characteristic of the potential reservoir fluid), and the given well control (rig) equipment.

5. The proposed rule **§ 250.413 & § 250.414** should be combined and amended. There should be no mandatory "one-half pound per gallon below the lesser of the casing shoe pressure integrity….". This in itself may lead to unsafe (or less safe) practices as an operator decides to maintain a lower mud weight than prudent in order to satisfy the rule leading to a higher potential for an influx. An alternative is discussed below:

   The suggestion includes improving the presentation of the information in the proposed rule. It also includes an assessment as to whether an influx can be circulated out using a conventional well control method and considering other factors such as choke and kill line friction pressures etc… It also includes an assessment of the uncertainties with respect to pore pressure and fracture gradient. These could be resolved for the case of development drilling. For the suggestion, there is no "hard and fast rule" but the information presented is transparent and the operator stands behind the decision (and margin) accepted.

   Note that 0.5 ppg is 260 psi at 10000 ft depth & 780 psi at 30000 ft depth-perhaps this should be considered.

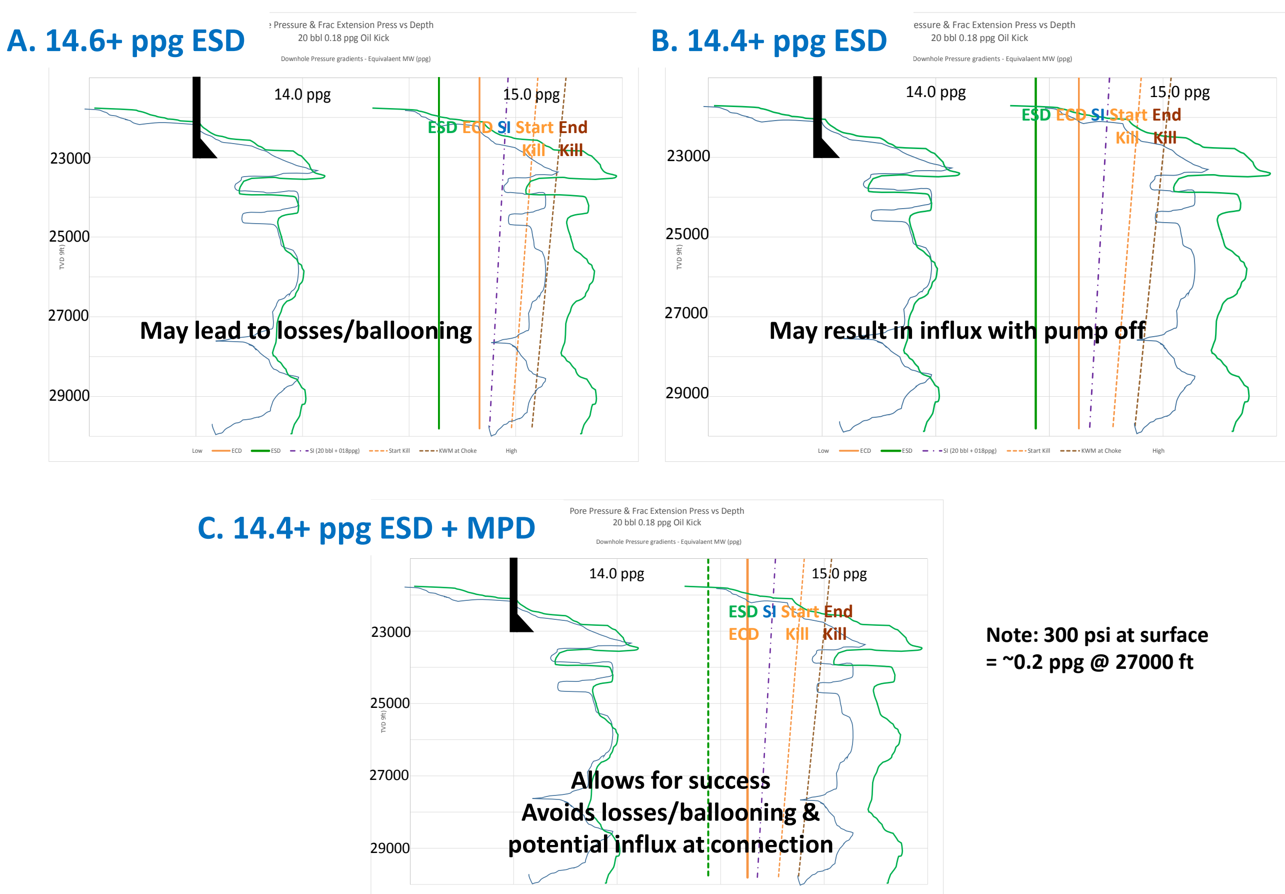


Fig 3. Example of Choices for Selection of Mud Weights – Small Drilling Operations Window

The proposed rule includes **§ 250.414 para (2).** In the above example, it is clear that Choice A provides less than the "required 0.5ppg margin". However (and for the estimated pore pressure and fracture gradient) it is clear that Choice A reduces the probability of an influx occurring.

By contrast Choice B follows the proposed rule but increases the potential for an influx.

In comparing Choice A and Choice B and given that the best estimate of pore pressure (including uncertainty) is the same in both cases, it is obvious that Choice A provides less potential for an influx.

If a pore pressure exists which has the potential to cause an influx in Choice A, and the same pressure influx were taken following Choice B, then the potential for losses would be essentially the same in both cases. The only merit to choosing Choice B is that it might provide more "warning" of a pore pressure increase due to increasing gas levels, but this method of pore pressure detection is only a part of the detection process at this time (it used to be the primary method of pore pressure assessment).

Choice C introduces the potential use of active MPD (Managed Pressure Drilling). (it could be argued that Choices A & B are essentially MPD, but without the "active" equipment)

The goal of this proposed suggestion is to allow the operator to make a sensible (yet appropriate) choice, rather than forcing a solution which may well result in a less safe choice. It also allows for uncertainties in estimations to be articulated and it allows for the magnitude of a "target" influx to be established (target kick tolerance).

The choice made would be transparent to all and (of course) subject to adjustment should the underlying estimation of pressure change.

Note: the use of a 0.5 ppg margin is historical. It made sense in a time when operators drilled with minimum mud weight and pore pressure estimation was largely based on gas readings. We have moved on from this approach.

6. **§ 250.416** should be amended to address "What must I include to properly recognize and deal with hydrocarbons in the marine riser above the subsea BOP?" rather than "What must I include in the diverter description"

   A significant threat to crews and for a subsequent blow-out stems from the lack of equipment to deal with and the lack of instrumentation to identify hydrocarbons that have travelled above the BOP and into the marine riser.

   Typically current rigs have zero riser instrumentation (for detecting/tracking hydrocarbons within the marine riser) and are equipped with a diverter system where the diverter is located above the slip joint and is incapable of placing any backpressure upon the fluids in the riser.

   The design and specification of the riser has also been unfortunately subjected to a too simple analysis, based on single gas bubble (in WBM) theory.

   Realistic well fluids and their interactions with SOBM have a completely different characteristic.

   Even with gas and a WBM, the characteristics of the fluids are more complex than the typical existing analysis allows.

A summary of suggested equipment is given below:

A. Water Based Mud (WBM) & (Dry) Gas Influx

The current equipment will probably suffice. For a small volume of gas (50 bbl or less, dependent on water depth), it is likely that a policy of wait/pump ¼ of riser volume/wait/pump ¼ of …… etc will result in dispersion of the gas bubble. The riser can then be pumped clear (at a reduced rate) with returns routed to a MGS. A large volume of influx will flow naturally and must be routed to the diverter.

Riser instrumentation to confirm that the volume of gas does not exceed a limit should be included. This may be in the form of "distributed" accurate pressure gauges such that differential pressures can be assessed.

B. SOBM & Gas or Oil (with associated gas) or WBM & Oil (with associated gas)

The characteristic of these fluid combinations is very different to the dry gas + WBM system.

Periods of "waiting" do not result in any hydrocarbon dispersion. As a result, a quantity of hydrocarbon will arrive at surface in a concentrated mass. If no backpressure is placed upon the hydrocarbon it can flash off very violently, resulting in a significant mud flow and with enough of a gas cloud to provide the fuel for an explosion if a spark is encountered.

The logical approaches to dealing with this situation are:

i. Know the hydrocarbon is there – riser detection system
ii. Go overboard (diverter system), but preferably:
iii. Impose back-pressure to calm down gas coming out of solution and then either go overboard or route back through MGS to rig depending on the volume type of hydrocarbon

In this case it is hard to argue that provision of back-pressure (i.e. use of a Riser Gas Handler or use of a Rotating Control Head (part of an MPD system) each one located below the riser slip joint) should not be required.

Riser instrumentation to determine the existence and the quantity of hydrocarbon is essential.

If no Riser Gas Handler/Rotating Control Head is installed and the riser instrumentation indicates the presence of significant hydrocarbon (significant may mean the combination of a quantity/distribution of hydrocarbon and potential gas content – a very low GOR oil will result in very low quantities of gas) or cannot confirm that it is insignificant, then it is a given that returns should be made directly to the sea through the diverter system with no returns back to the rig.

For both SOBM and WBM (A and B above), development of detailed equipment specifications and operational procedures will require significant industry discussion and co-operation. This issue is seen as a very significant gap. It was certainly a very important part of the chain of events that led to the Macondo blow-out. As part of this effort focus must be placed on the decision to disconnect (or not). Such action will in some cases increase the flow of hydrocarbon to the rig floor. In other cases such flow will diminish. It is suggested that analysis be in place such that the appropriate decision can be made.

7. Perhaps most important – much more emphasis on **well and rig specific training** for the crew. This involves thoroughly analyzing (realistic modeling) what can happen for a particular well and then communicating what is understood to the rig crew. For example, a gas influx from 6000 ft depth 5-Darcy reservoir in an 8 ½" hole with WBM, will look very different to an oil influx at 20000 ft depth with a 100-mDarcy reservoir in 12 ¼" hole when SOBM is being used. The magnitudes of what will be seen, what must be reacted to and how and the timing of events will be very different.

   This topic is (almost) mentioned in **§ 250.710 para (b)**. The intent of the above suggestion is to take this much further, such that the rig operations team is fully informed of the characteristic of the well and will take charge and ownership of all events at the wellsite in a logical way.

4. Concluding Remarks

Given the possibility of a blow-out in GOM waters the necessity of mitigation measures to limit the volume of such a blow-out is essential. However, these measures must be effective (defined as limiting the timeframe and flow-rate of an event if it occurs) and it must be recognized that preventing such an event in the 1st place is more important in that it avoids the pollution and ensures the safety of personnel.

The proposed rule should:

1. Provide a stronger emphasis on the identification/verification and communication of the barrier types and condition such that all parties involved are on the same page
2. Give more emphasis to accurately measuring flows to and from a well
3. Remedy the current lack of control devices/instrumentation installed with deep-water marine riser systems
4. Require well specific/rig specific training for personnel
5. Require realistic well control modeling of the well systems such that relevant issues can be determined, analyzed and then discussed in detail with the operations teams. This will also allow focus on events which could occur on the upcoming well operation rather than an approach defined too closely by a previous blow-out incident, or events relevant to other wells.

It is also essential that the requirements on mitigation of blow-out consequences do not impact the resources and focus of an operating company and its personnel with respect to what should be the primary focus (i.e. prevention).

I respectfully submit the above as comment.

Please feel free to contact if there are any questions or if clarification is required.

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