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November 3, 2016

Doug Morris
Chief Office of Offshore Regulatory Programs
Bureau of Safety and Environmental Enforcement
U.S. Department of the Interior
1849 C Street, NW
Washington, DC 20240

RE: BSEE Report 2014-02, QC-FIT Evaluation of Seal Assembly and Cement Failures Interim Summary of Findings (dated December 2014)

Via email

Dear Mr. Morris:

API would like to take this opportunity to respond on the above-referenced report to review the performance of key equipment involved in the Main Pass 295 underground blowout that occurred February 10, 2013 and determine if there were industry-wide issues that needed further evaluation. Every incident is both one too many and a powerful reminder for API and Industry to continually improve training, operating procedures, technology and industry standards.

API is a national trade association that represents more than 650 members involved in all aspects of the oil and natural gas industry, including exploring for and developing oil and natural gas resources in the Gulf of Mexico (GOM).

Our members recognize that offshore operations must be conducted safely and in a manner that protects the environment. The U.S. offshore industry has advanced the energy security of our nation and contributed significantly to our nation's economy.

In addition to the discussion at the BSEE Domestic and International Standards Workshop and the Technical Session during the API Exploration and Production Summer Standards Meeting in San Francisco on June 23, 2105, API engaged subject-matter experts and reviewed the above-referenced publically available QC-FIT Report #2014-02, letter of transmittal to Director Salerno and Director Salerno's January 20, 2015 memorandum regarding the report and provides the following response.

Based on the information contained in the report, there are no defendable technical findings to support the notion the loss of well control on MP 295 was the result of failure of the 22-in casing cement sheath, the 18-in casing cement sheath or the sub-mud line casing hanger seals. Key data are missing such as accurate formation pore pressures and fracture pressures, information on the type of influx (water/gas/oil), the results of the 22-in casing or 18-in casing liner shoe leak-off tests, data collected from the cementing operations and casing torque make-up records. Without this information it is impossible to assess all possible flow paths. Unless additional work was completed and not presented in the report, all potential root causes of the loss of well control on MP 295 have not been fully evaluated. The observed condition of the pulled sub-mud line seal assembly would suggest the most likely flow path was not consistent with the findings of the report. A technical discussion is included in Attachment 1 that further explains our position. Attachment 2 provides the API response to each of the recommendations made in the report.

As written, QC FIT Report #2014-02 provides no technical basis to suggest that industry standards or government regulations are insufficient thereby requiring more prescriptive requirements to improve safety. While many of the recommendations contained in the report are already being implemented, the report did help identify expanding API Spec 17D and draft API Specification 19LH to cover guidelines for the design and qualification of seal assemblies.

Safety is a core value for the oil and natural gas industry. API and our members are committed to safe operations and appreciate the opportunity to comment on this report. We propose a meeting with you and your staff to continue these discussions as we all strive to improve safety in the offshore industry. Please contact me at 202-682-8439, or hopkinsh@api.org to schedule the meeting.

Sincerely,

Holly A. Hopkins

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Holly A. Hopkins

Attachment 1
Technical Discussion

Cementing Operation Assessment:

When evaluating a cementing operation for the purposes of determining if a barrier element has been established, the observations made while drilling the hole section, the practices employed prior to cementing, the cement design and laboratory testing results, the placement of centralizers, operational evidence (density/rate control, surface pressure response, etc.), the pressure testing of the casing, experiences during the drillout of the casing shoe track and pressure testing when drilling new formation beneath the casing shoe, when taken collectively can be used to determine the likelihood that a barrier element is in place. Additional information on establishing and verifying barrier elements is found in API Standard 65-2 and API RP 96.

The well construction of MP 295 entailed the driving to refusal of a 36-in structural casing to 540 ft measured depth at rotary kelly bushing (MD RKB), followed by the setting of a 22-in conductor casing in a 28-in drilled hole at 1000 ft (MD RKB). The top of cement was reported at 318 ft MD RKB. The 18-in surface liner, placed in a 24-in drilled hole, was set at 3205 ft with the sub-mud line system seal assembly set in the 22-in casing at 703 ft MD RKB. The water depth at the MP 295 drilling site was reported to be 218 ft. Details are found in Figure 4 schematic, taken from the BSEE QC-FIT report.

It is important to note that the gas flow on MP 295 was encountered while drilling a 20-in hole at 8261 ft MD RKB, after both the 22-in casing and 18-in surface liner had been installed.

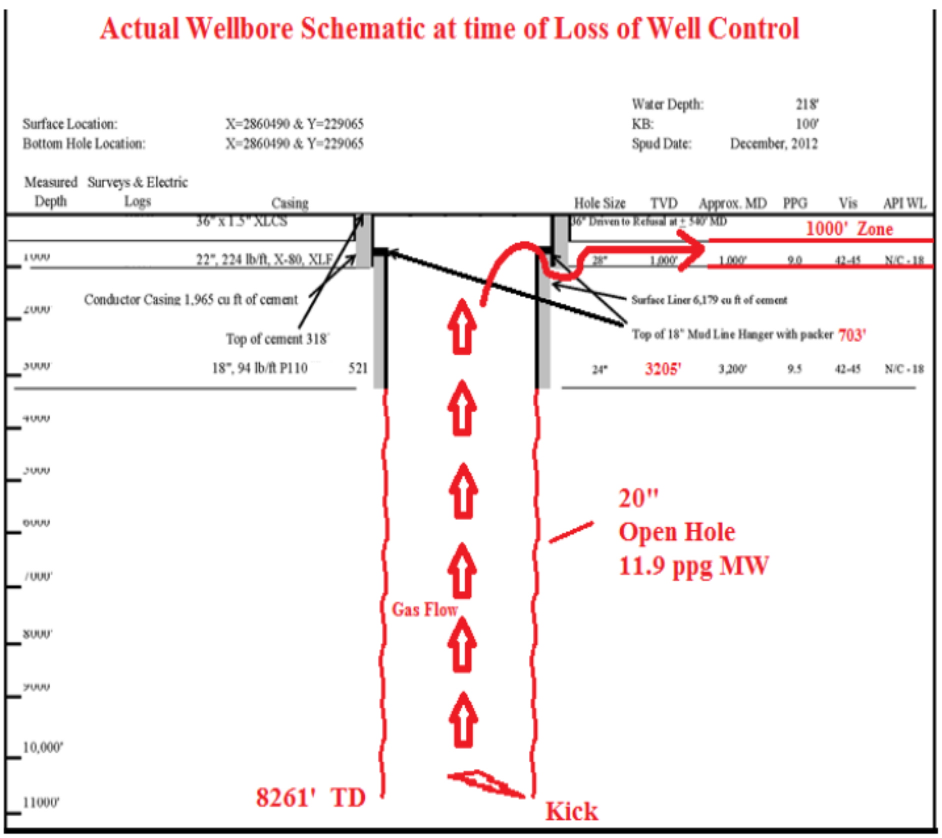

FIGURE 4: ACTUAL WELLBORE SCHEMATIC AT TIME OF LOSS OF WELL CONTROL[8]

In order to effectively access the quality of the two cementing operations conducted prior to the loss of well control event, the following parameters can be evaluated for each cementing operation. The parameters are summarized as follows.

22-in Structural Casing set at 1000 ft MD RKB:

- Did the pre-drill subsurface assessment indicate potential flow zones or faults in this section of the wellbore? (Yes/No)
- Were gas or water flows experienced during the drilling of the hole section? (Yes/No)
- Was the well circulated prior to cementing? (Yes/No)
- Was the casing string adequately centralized? (Yes/No)
- Was the hole in a stable condition (no flow, no losses) prior to running casing? (Yes/No)
- Was there any indication of wellbore instability when running casing? (Yes/No)
- Was the cement slurry design appropriate for the actual well conditions? (Yes/No)
- Were the cement testing results (Thickening Time, Compressive Strength, Free Fluid, etc.) within acceptable limits? (Yes/No)
- Was the cementing operation conducted as per plan (cement density target met, cement mixing/displacement rate target met, etc.)? (Yes/No)
- Was the lift pressure experienced during the operation within the expected value? (Yes/No)
- Were significant losses experienced during the cementing operation? (Yes/No)
    - If yes, was the uppermost potential flow zone covered? (Yes/No)
- Was the top of cement at the planned depth? (Yes/No)
- Did the floats hold? (Yes/No)
- Did the casing pressure test to the desired value before drillout? (Yes/No)
- Did the shoe track contain set cement during drillout? (Yes/No)
- Was the planned leak off test (LOT) value obtained when the shoe was drilled out? (Yes/No)
- Was the LOT pressure signature indicative of a contained pressure system? (Yes/No)

In practice, based on the responses to the parameters described above, it can be possible to determine with reasonable confidence if the 22-in casing is isolated and a barrier element established. In the case of the MP 295 well, the isolation of this area of the wellbore is critical in that gas flow encountered deeper in the well is thought to have charged a formation located at approximately the 22-in casing setting depth.

18-in Surface Liner set at 3205 ft MD RKB:

- Did the pre-drill subsurface assessment indicate potential flow zones or faults in this section of the wellbore? (Yes/No)
- Were gas or water flows experienced during the drilling of the hole section? (Yes/No)
- Was the well circulated prior to cementing? (Yes/No)
- Was the casing string adequately centralized? (Yes/No)
- Was the hole in a stable condition (no flow, no losses) prior to running casing? (Yes/No)
- Was there any indication of wellbore instability when running casing? (Yes/No)
- Was the cement slurry design appropriate for the actual well conditions? (Yes/No)
- Were the cement testing results (Thickening Time, Compressive Strength, Free Fluid, etc.) within acceptable limits? (Yes/No)
- Was the cementing operation conducted as per plan (cement density target met, cement mixing/displacement rate target met, etc.)? (Yes/No)
- Was the lift pressure experienced during the operation within the expected value? (Yes/No)

- Were significant losses experienced during the cement operation? (Yes/No)
    - If yes, was the uppermost potential flow zone covered? (Yes/No)
- Was the top of cement at the planned depth? (Yes/No)
- Did the floats hold? (Yes/No)
- Did the casing pressure test to the desired value before drillout? (Yes/No)
- Did the shoe track contain set cement during drillout? (Yes/No)
- Was the liner top pressure test successful? (Yes/No)
- Was the planned LOT value obtained when the shoe was drilled out? (Yes/No)
- Was the LOT pressure signature indicative of a contained pressure system? (Yes/No)

Once again, based on the responses to the parameters listed above, it can be possible to determine with reasonable confidence if the 18-in surface liner is isolated and a barrier element established.
The BSEE QC FIT report did not provide sufficient details to allow the assessment of the quality of installation of either of the 22-in casing or the 18-in surface liner that were set before the loss of well control event occurred. As such, it should not be presumed the loss of well control was due to the failure of the cement sheath of either casing.

Gas Migration:
As seen in Figure 4 of the BSEE QC FIT report it is suggested the gas flow entered the 20-in drilled wellbore at 8261 ft MD RKB, flowed up the wellbore and through the seal assembly or seal assembly/cement at the top the 18-in surface liner, then flowed down the 22-in conductor casing/18-in surface liner annulus and around the shoe of the cemented 22-in conductor casing eventually charging a formation at 1000 ft MD. However, the condition of the seal assembly after retrieval does not support the BSEE contention that flow through the seal assembly was a preferential flow path.

Gas migration can occur as the cement slurry transitions from a liquid to a solid material. Gas migration control additives function during this transition by inhibiting the movement of gas through the cement sheath. Once sufficient static gel strength within the setting cement is established, the role of the gas migration control additive is complete. Gas migration control additives provide no protection from gas flow after the cement has set. The flow path proposed in Figure 4 of the BSEE QC FIT report would not have been prevented by the presence of gas migration control additives in the cement systems used on the 22-in conductor casing or the 18-in surface liner because the exposure to gas occurred after the 22-in conductor casing and the 18-in surface liner had been installed and the cement set.

Gas migration through set cement may be the result of a failure of the cement sheath through mechanical stress or inadequate mud displacement during the cementing operation, leaving mud filled channels in the cemented annulus. These mechanisms are addressed in API Standard 65-2. Additional information gas migration may be found in *Well Cementing*, (Nelson and Guillot), Second Edition 2006, Chapter 3, Annular Formation Fluid Migration.

In conclusion, requiring the addition of gas migration prevention materials to the cement in all shallow casing or liner designs would not reduce the risk of flow experienced on the MP 295 well.

Seal Assembly:
As contained in the BSEE QC FIT report, the OEM of the seal assembly states that it passed three hydrostatic tests, two in the field and one after retrieval. Further, when removed from the wellbore, the 18-in surface liner hanger seal showed no evidence of erosion due to gas bypass. BSEE claims that seals

used on the casing hanger assembly are rated to only 75°F. API believes this to be incorrect based on an error in the manufacturers literature. We believe the hanger seals, along with the all elements of the casing hanger system, were tested to API Specification 6A temperature classification V (35°F to 250°F).

CONCLUSIONS:
As stated in the BSEE QC FIT report executive summary, “Subsequent analysis indicated that there were several other potential points of failure which included damaged casing and/or damaged casing threads”. Unfortunately, the findings supporting this statement were not contained in the report and further demonstrate the vagueness of technical substantiation supporting the report’s findings. It is also believed that additional flow paths to those noted above may not have been evaluated.

As a response to the contention that a failure of the cement sheath and/or casing hanger seal assembly was a possible cause of the loss of well control event, based on the information contained in the report, there are no defendable technical findings to support the conclusion the loss of well control on MP 295 was the result of failure of the either the cement sheath or the casing hanger seals.

Attachment 2
BSEE SUMMARY OF RECOMMENDATIONS/API DPOS RESPONSE:

The following are the combined recommendations from this QC-FIT evaluation

1. Based on the issues identified in this report, BSEE should request that API perform an assessment of API Spec 17D and draft API Specification 19LH to determine whether these documents provide adequate guidelines for the design and qualification of this equipment.

API Response:

API has reviewed both API Spec 17D (2nd edition) and the draft of API Spec 19LH in development. API Spec 17D does contain requirements for validation of seal assemblies using gas as a test medium (section 5.1.7.3). Work is currently underway to create API Spec 17D (3rd edition). BSEE personnel are invited to be part of this effort.

Draft API Spec 19LH was reviewed and determined not to be applicable to sub-mud line hangers. BSEE regulations and industry standards should require that all downhole equipment is capable of performing at all reasonably anticipated downhole operating environment conditions including temperature, pressure, fluid, gas, and hydrocarbon service.

2. BSEE regulations and industry standards should require that all downhole equipment is capable of performing at all reasonably anticipated downhole operating environment conditions including temperature, pressure, fluid, gas, and hydrocarbon service.

API Response:

API agrees equipment and materials should be designed to be fit for purpose for each expected well situation. A key intent of API standards is to provide a consistent framework of testing and evaluation protocols to assure these goals are met. As each well environment is unique, it is incumbent on the engineer to design the systems in the well that meet the requirements of that unique environment. Current regulations do require professional engineer review of well designs, including the fitness for purpose of downhole equipment.

Neither BSEE regulations nor API standards should intend to treat all wells as being identical by offering single solutions to all designs.

3. Operators should design barrier systems and equipment for gas service unless there is information from the Geological & Geophysical (G&G) review or other information that clearly indicates otherwise.

API Response:

As noted above, each well situation is unique and the well designs should address the actual conditions of the well. Barrier systems are designed to meet the requirements of the well environment and should not be based on the performance of a single component. The barrier should depend on the total system, which consists of multiple barrier elements working in concert. Individually the components may not address the full well needs, but in concert will comprise an effective barrier system. It is the barrier system that will provide the isolation rather than any single piece of equipment.

4. BSEE regulations should consider requiring that operators verify the capability of any downhole equipment that acts as a barrier with manufacture certification or third party independent inspection.

API Response:

API Standards and Specifications address equipment and procedural requirements, providing the user with consistent testing protocols and assurance the equipment being used will meet the requirements of the specification. However, these standards do not address the application of equipment to a particular set of well conditions, as standards cannot cover all contingencies. Current regulations require professional engineering review, which is intended to include the appropriateness of the equipment being used in the well.

There are instances where there is no standard process for verification of particular pieces of equipment. Lacking those standard protocols, individual certification or independent inspection would not provide the assurance being considered by BSEE. An independent inspector would have no standard by which to judge the effectiveness of the equipment to act as a barrier, nor would the manufacturer be able to build the equipment to a consistent performance requirement.

Prior to drafting new regulations for equipment certification or inspection, API would recommend a review of what equipment BSEE would consider covering by regulation and establish if there are indeed existing standards or specifications that would allow for consistent manufacture and inspection of that equipment.

5. Industry standards should provide sufficient guidelines for ensuring that seal systems are adequately designed and tested pursuant to standardized protocols.

API Response:

Many existing industry standards already provide validation requirements for seals and seal systems used in downhole and surface equipment. As these standards are routinely updated, API welcomes BSEE to participate in the development/revision of these standards to insure they meet both industry and regulator expectations for performance.

6. BSEE and operators should more closely examine any shallow casing or liner cementing acceptance criteria to evaluate the need for the addition of a gas-migration control package to the cement system.

API Response:

API agrees examining the need for gas migration control in cements is part of proper well design. The need for gas migration control is addressed in API RP 65 and Standard 65-2, which have been adopted by reference into regulations.

The BSEE QC FIT report provides no evidence that inclusion of gas migration prevention additives to the cement in all shallow casing or liner designs would reduce the risk of flow described on the MP 295 well. In practice, owing to the manner by which gas migration additives function, the inclusion of gas migration prevention additives to the cement in all shallow casing or liner designs would not reduce the risk of flow described on the MP 295 well.

7. BSEE and industry should assess whether there is a need for additional research related to establishing best practices for casing or liner cementing, or if the previous MMS studies need redistribution to the industry for further discussion due to the time lapse from issuance.

API Response:

API agrees further discussion is merited, and would suggest a review of the existing data and MMS studies with members of BSEE, the industry and third party groups would be appropriate. Assessing potential need for additional research should take place after this data review. API feels it appropriate to include personnel from the U.S. Department of Energy's National Energy Technology Laboratory (NETL) in the review group. NETL brings together a uniquely qualified group of unbiased researchers and could provide new views on the currently available data sets. NETL has provided invaluable assistance to standards development in the past and continues to be a valued asset to both BSEE and industry.

8. BSEE should assess whether a well design which incorporates the use of a shallow liner is adequate from a risk standpoint. This review should include an assessment of current industry standards, pressure testing requirements and identification of steps that should be taken to ensure that risks are reduced to an acceptable level.

API Response:

Shallow liners are incorporated in numerous well designs and have been used successfully for many years. The technology is proven and effective and it is incumbent on the engineer to determine its applicability to each individual well. A well consists of multiple cemented casing strings, typically working as a system to ensure isolation of potential flow paths. A shallow liner is one part of that system and should not be analyzed in isolation. As noted, BSEE requirements for professional engineer review of these designs includes a risk assessment of all materials and systems being used in the casing design, which would include pressure testing requirements. API would recommend the proposed review be a part of the scope of work assigned to the work noted in response to #1. In this way, BSEE personnel actively participate in the process of review and development of any needed standards.

9. BSEE should conduct an engineering design analysis of standard industry practices related to liners and sub mud line seals and cementing to address the issues listed below:

a) What is the design purpose of the seal? Is it considered a temporary seal for the purpose of ensuring a successful pressure test or is it part of a dual barrier system (i.e. seal assembly and cement) that should last for the life of the well?

API Response:

As noted above, API work groups will be charged with addressing the design and qualification of sub mud line seals. In this well design, it is important to understand that the sub-mud line seal was not designed for gas service. In this case, the sub-mud line seal and cement are two elements of a barrier system.

API Standard 65-2 defines a barrier as: "*A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed*." This definition contains several important elements, the first being a barrier is a component or practice. This is intended to highlight a barrier may include components such as seals or cement, but also operational practices such as controlling fluids and pressures.

The definition goes on to note the component or practice contributes to *total system reliability*. This wording is intended to highlight it is the total system that functions as the barrier rather than the reliance on any one specific component or element. Finally, the definition notes the component can only properly function as a barrier element if it is properly installed. This key part of the definition refers back to the operational practices found in Standard 65-2 as well as industry practices to assure proper installation of equipment and materials into wells.

A barrier that meets the definition as found in Standard 65-2 and operated within its design limits should function for the life of the well unless specifically designed to do otherwise.

b) Is the seal or the cement considered to be the primary barrier?

API Response:

Cement can and does function as a primary barrier in a well if properly designed and placed. API Standard 65-2 address cement placement and design as well as define when cement may be considered a barrier. There is however no distinction in cement being a barrier or a "primary barrier". Such a distinction would depend on application and well architecture. The most common instance where cement may be considered the primary barrier is the performance of a shoe test following drill out of a primary cement job. In this case it is clear cement is the only barrier element being tested. With sub-mud line hanger systems (such as the one used in Main Pass 295) that incorporate both cement and a seal element, cement functions as an element of the barrier system rather than the primary barrier. In cases where qualified mechanical well barrier elements are used in conjunction with cement, (e.g. integral gas-tested liner top packers or casing hanger seal assemblies with lockdown mechanisms) the tested mechanical well barrier element and the verified cement can act as two independent well barrier elements.

As discussed below, the nature of the installation of the cement and seals does not allow for independent testing of each individual element. Rather, as noted in the BSEE report, a successful test demonstrates functionality of the barrier system.

c) Shouldn't both barriers, seal and cement, be independently tested? If so, how should these tests be conducted in the field and what regulatory changes would need to be made by BSEE to require such tests?

API Response:

This question points back to the seal and the cement being independent and unique barriers rather than parts of a barrier system. In this particular well design, there are no known test methods to allow independent testing of the two barrier elements with any degree of certainty. To attempt to test the individual components separately would be to invite misinterpretation of the data which could lead to falsely assuming each element is independent of the other. As noted in the definition of a barrier found in Standard 65-2, individual components contribute to the total system reliability if properly installed rather than acting as the only barrier. Per the OEM, the seal assembly was tested twice in the field during installation. Cement compositions are routinely tested in a laboratory to determine specific set properties including compressive strength as a function of time.

d) Are current BSEE pressure testing requirements adequate enough to verify the integrity of the system? Should BSEE regulations or industry standards be modified to include a requirement to negatively pressure test shallow casing strings, sub mud line and liner systems (e.g. conductor and surface strings) to assess the pressure integrity of either the tubular or hanger seal prior to drilling out of the shoe? (The current BSEE requirement is for a positive pressure test on conductor and surface strings.)

API Response:

Pressure testing of any well system should be performed to assure the system will withstand the anticipated pressures in the direction of that anticipated pressure. Negative pressure testing is appropriate when the density of the fluids in the well are being reduced and there is a potential for well flow.

Assessing the pressure integrity of the system through positive pressure testing is appropriate for these situations and is important for assuring the integrity of the system.

e) What type of reliability data exists for either barrier (i.e. seal assembly and cement) during their service life? Is there a method to determine the reliability of either one of these components after the initial pressure test? What are the risks involved in being unable to independently test redundant barriers?

API Response:

As noted above, within Standard 65-2, the definition of a barrier is "*A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed*." Once proper design and installation of the barrier is achieved, the only remaining variable is maintaining that barrier within its design envelope. Provided this is done, the barrier system will function for the life of the well with minimal risk of failure.

Repeated testing will add stress to the barrier and must be considered in the initial barrier design. Just as bending a piece of wire repeatedly can eventually result in its failure, unnecessary stressing of the system by excessive testing may weaken the system, potentially reducing the operating envelope.

Referring back to the Standard 65-2 definition of a barrier, a key component of that definition are the words "*if properly installed*". This implies there is some method to assess the installation process of the barrier, be that through adherence to operational practices or performance of some type of post-installation testing. While physical testing of independent components of barrier systems may not be possible, assuring the component has been properly installed will reduce the risks associated with that redundant barrier.

f) Should BSEE consider a revision to regulation 30 CFR 250.423(a) or request industry to modify existing standards to develop a requirement to increase the casing pressure test duration? This would apply to conductor, surface casing strings and liners - from a 30-minute test, with less than a 10 percent pressure decline, to a 60-minute test, with less than a 10 percent pressure decline.

API Response:

In typical field operations pressure testing failures manifest themselves very quickly. It is believed that extending the required test period to 60 minutes would not, in general, improve safety.