QC-FIT EVALUATION OF SEAL ASSEMBLY & CEMENT FAILURES INTERIM SUMMARY OF FINDINGS

Bureau of Safety and Environmental Enforcement

Office of Offshore Regulatory Programs

Internal QC-FIT Report
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EXECUTIVE SUMMARY

On February 10, 2013, a rig was conducting drilling operations on Main Pass Block 295 ("MP295") in the Gulf of Mexico (GOM), when an underground loss of well control event occurred. The loss of well control resulted in gas flow into a shallow sand, below the conductor casing shoe in the well. This loss of well control incident created a risk of broaching of the well to the seafloor, which created significant risks to the crew, the rig, and the environment.

The well design included a dual barrier system in the annulus that should have prevented uncontrolled flow of hydrocarbons. The initial review determined the dual barrier system failed, allowing gas flow to penetrate a shallow formation below the conductor casing shoe. The first possible failure point was the sub mudline casing hanger seal assembly. This system was designed to hold pressure from the well up to the designated pressure and temperature ratings of the seal assembly. The second possible failure point was the cement column within the conductor casing and surface casing annulus. The cement column should have created a barrier that prevents hydrocarbon flow from the well to the surrounding environment. Subsequent analysis indicated that there were several other potential points for failure which included damaged casing and/or damaged casing threads.

A Quality Control Failure Incident Team (QC-FIT) was assembled to perform the following: conduct a technical evaluation of the equipment involved in this incident to determine if there were global quality assurance/quality control (QA/QC) issues that needed addressing by BSEE and/or industry issues related to the use of the dual barrier systems. The goal of this report is to provide a general assessment of industry equipment and engineering design related to these systems rather than making a definitive determination concerning the loss of well control on MP295.

This technical evaluation includes a review of available data, relevant industry standards, and input from various subject matter experts. A comprehensive recommendations list is outlined at the end of this report. These recommendations are applicable to dual barrier seal systems and equipment used in well construction that serves as barriers.

Summarized key findings and recommendations are:

- Existing industry practices and BSEE regulations related to pressure testing may not be adequate to evaluate the integrity of either the seal assembly or the cement column. BSEE should consider modifying its regulations to ensure that the integrity of these barriers can be verified after installation.
- Operators should be required to verify that any pressure containing equipment installed downhole has been designed, tested, and rated for any potential loss of well control condition to which it might be exposed during its service life.

- A comprehensive analysis of well designs utilizing shallow liners and sub mudline casing hangers needs to be performed by either BSEE or the industry to ensure that best engineering practices are being utilized to minimize the risk of a loss of well control event.

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BACKGROUND

In an effort to design the well in a manner that addresses all safety, environmental concerns, and operational issues, operators often run a casing hanger to hang off a liner string in the well instead of running a full casing string back to the wellhead. [1] While a liner string is very similar to a full casing string in that it is made up of separate joints of tubulars, the liner string does not run the complete length of the well back to the wellhead. After running the liner, a cement job anchors the liner string in place and provides zonal isolation of potential or known flow zones.

A related type of equipment that is commonly used in the upper part of a casing string in the GOM is a mudline suspension system. This type of system consists of: (1) a hanger system that allows a surface liner to be hung within a recess in a sub mudline casing hanger, and (2) a seal assembly that seals the annulus between the conductor and surface liner (see Figure 1). The use of this system gives an operator the flexibility to utilize additional casing strings during drilling operations.

The seal assembly used in the MP295 well (see Figure 2) was an 18 inch sub mudline casing hanger system (see Figure 3). This sub mudline casing hanger system was set at approximately 703 feet measured depth (see Figure 4). The approved well design included cement from 3,200 feet to the top of the surface liner at 703 feet (see Figure 5).

BSEE regulations require liner systems to be pressure tested. Section 250.425 states:

What are the requirements for pressure testing liners?

> (a*) You must test each drilling liner (and liner-lap) to a pressure at least equal to the anticipated pressure to which the liner will be subjected during the formation pressure-integrity test below that liner shoe, or subsequent liner shoes if set. The District Manager may approve or require other liner test pressures.*
> *(b) You must test each production liner (and liner-lap) to a minimum of 500 psi above the formation fracture pressure at the casing shoe into which the liner is lapped.*
> *(c) You may not resume drilling or other down-hole operations until you obtain a satisfactory pressure test. If the pressure declines more than 10 percent in a 30-minute test or if there is another indication of a leak, you must re-cement, repair the liner, or run additional casing/liner to provide a proper seal.*

BSEE regulations require mudline systems to be pressure tested. Section 250.423 states:

What are the requirements for pressure testing casing?

[1] See the Appendix for a description of the terminology used throughout this report regarding equipment, as well as a schematic of the well design involved in this loss of well control event.

(c) You must perform a negative pressure test on all wells that use a subsea BOP stack or wells with mudline suspension systems. The BSEE District Manager may require you to perform additional negative pressure tests on other casing strings or liners (e.g., intermediate casing string or liner) or on wells with a surface BOP stack.

The purpose of the liner pressure test is to verify the competency of the tubular, the annular cement column, and the cement at the liner shoe to ensure that a sufficient barrier to flow exists before drilling out. Failure of the system to hold pressure during the test can result in costly remedial action.

ASSESSMENT

Following the incident on MP295, BSEE convened the QC-FIT within the Office of Offshore Regulatory Programs to evaluate any technology or safety issues associated with the use of liners, and mudline systems in Outer Continental Shelf (OCS) wells and associated best cementing practices. In particular, the QC-FIT was tasked with determining if there were industry wide issues involving equipment or processes that needed further action by BSEE and/or the industry. The summary of this evaluation and recommendations are listed below.

HANGER INDUSTRY STANDARDS

Currently, there are no industry standards that exclusively address liner hangers or seals. Two standards address some design criteria for this type of equipment:

- API Specification (Spec) 17D standard (Design and Operation of Subsea Production Systems – Subsea Wellhead and Tree Equipment) addresses the design methodology, verification and validation of wellhead production hangers, sub mudline casing hangers and seals.
- API Recommended Practice (RP) 19LH (Liner Hangers) is currently being drafted by an API subcommittee. This new standard will address specifications for downhole production liner hangers. When complete, this document will address how to verify (design verification) and qualify (design validation) a liner hanger for service. The standard is anticipated to contain two separate test standards for liner hangers; one for gas qualification and one for liquid (water) qualification. The standard will not address the type of shallow liner equipment that was used in the MP295 well.

The sub mudline casing hanger used in the MP295 well was designed to the first edition of API 17D which only required hydrostatic testing with water. The current (second) edition of API 17D was revised in 2011 to require gas qualification testing of this equipment.

RECOMMENDATIONS:

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

SEAL DESIGN AND QUALIFICATION

Manufacturing companies have different sub mudline casing hanger and liner designs based on the anticipated temperatures and pressures of the well and whether the equipment is being used in gas and/or liquid service. A gas service rating generally means that the equipment has undergone more rigorous qualification tests that measure sealing capability. The establishment of the proper rating is critical to ensuring that the equipment will perform as designed when installed in the well.

The sub mudline casing hanger seal installed for the MP295 well was rated for 75°F and liquid service. In actual operations, it was exposed to 90°F and high pressure gas, and was clearly not properly rated to the reasonably anticipated well conditions (i.e. "fit for service"). [2]

The impact of the use of an improperly rated seal in the MP295 well is unknown at this time. The OEM states that the seal assembly did pass three hydrostatic pressure tests; two in the field (upon installation and when the casing integrity test was run) and one when it was retrieved for a post mortem examination (after the loss of well control event). [3] At the post mortem examination, a third party reported that the seal assembly appeared to be in very good condition and exhibited no indication of erosion due to flowing of fluid or gas. Therefore, it is possible that the loss of well containment was due to other causes besides a seal failure. [4, 5]

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[2] There is disagreement among the involved parties in this loss of well control incident, as to the proper temperature rating of the seal. This disagreement however, demonstrates that critical information involving well containment equipment was not effectively communicated between the operator and OEM.

[3] As noted in other sections of this report, the field pressure tests appear to be directed at verifying the integrity of the dual barrier system (seal and cement), rather than testing each barrier independently. In addition, these tests were only hydrostatic tests and did not duplicate the actual wellbore conditions (gas service and temperature).The post mortem examination was performed onshore at both the OEM and third party facilities. The seal assembly was visually inspected, and the critical areas were dimensionally inspected and determined to be within tolerance, or slightly outside the original machined dimensions (which was expected and consistent with other retrieved seal assemblies).

[4] Other possible flow paths include damaged casing, leaking threaded connection, and flow around the 18 inch shoe. It is not known which of these potential flow paths resulted in the loss of well containment. The fact that the failure mechanism was, and still is, unclear raises the question of whether or not the operator should have continued drilling this well after this loss of well control event.

[5] Historically, cement logs have been poor at identifying leak paths or channeling (pathways) through cement; however, they are one of several tools used to determine the potential for a leak path. These tools suffer from interpretation errors and have limitations regarding identifying weaker cement versus a channel within the cement. The sonic log for this well appeared to show flow at the seal area.

It is clear to the QC-FIT that additional steps need to be taken to ensure that seals which are being used as barriers are adequately designed and tested to ensure that they are fit for service. Further, additional steps need to be taken to ensure that both operators and equipment suppliers effectively communicate information concerning expected service conditions.

RECOMMENDATIONS:

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

CEMENTING AND CASING DESIGN

Successful casing and cementing programs are especially critical for the shallow or top hole sections of a well – i.e. conductor and surface hole sections – to mitigate broaching of the wellbore fluids to the seafloor. If broaching of wellbore fluids to the seafloor occurs on the OCS: (1) it might be extremely difficult to eventually "kill the well," and (2) the seafloor may lose its foundational strength, inducing a cratering phenomenon which could result in the loss of a bottom supported rig or platform. To guard against the loss of well control in shallow sections, it is critical that special precautions be taken when designing casing and cementing programs.

Cement Design

Design concerns and risks involving the cementing of shallow casing, sub mudline and liner systems are not new. The Minerals Management Service (MMS) completed at least two studies that addressed these issues:

- Technology Assessment and Research Study Number 27: "Study of Cementing Practices Applied to the Shallow Casing in Offshore Wells."
- Technology Assessment and Research Study Number 195: "Analysis of Platform Vulnerability to Cratering Induced by a Shallow Gas Flow."

The industry has also taken steps in recent years to address these types of issues. API RP 65 (Cementing Shallow Water Flow Zones in Deepwater Wells) and API RP 65 – Part 2 (Isolating Potential Flow Zones During Well Construction) are both incorporated by reference into BSEE's regulations and highlight key points related to casing and cementing design.

The presence of gas in the formation during operations is a key consideration in designing the cementing and casing programs. [6] If not properly managed, there is a risk that formation gas could enter the wellbore during cementing operations and degrade the integrity of the cement job. Gas migration is most likely to occur during the interval of time when the cement transitions from a liquid to a gelled state and the hydrostatic head is reduced. Gas-migration control additives may be used in the cement slurry to minimize the risk of gas migration during this transition time.

Currently, there are no requirements in industry standards or BSEE regulations related to the use of gas control cement systems. One major operator stated they always design for the worst case scenario and add a gas migration control additive into all their cement jobs to reduce the likelihood of gas migration.

In the MP295 well, the cement system used for the liner did not contain a gas migration control additive system. The engineer that certified to BSEE the cement and casing program was adequate stated that he did not recommend adding a gas migration control additive to the surface casing cement job. [7] The sub-contractor believed such an additive would only be beneficial during the cement curing process and would be of minimal benefit beyond that point.

The cementing company responsible for performing the cementing of the liner stated that if they had received more information from the operator on the expected downhole conditions, they would have designed the cement job differently and would have designed the surface liner cement job as a gas-migration control cement design.

This disagreement between the parties in this loss of well control incident related to whether or not a gas-migration control cement was appropriate for this well design indicates that additional industry guidelines or research in this area are needed.

Casing Design

[6] In the Gulf of Mexico, the potential for encountering gas in shallow water is more probable than in deep water environments.

[7] Gas migration control additives are not addressed in BSEE regulations. BSEE regulation §250.420 reads: What well casing and cementing requirements must I meet? (6)(i) Include a certification signed by a registered professional engineer that the casing and cementing design is appropriate for the purpose for which it is intended under expected wellbore conditions, and is sufficient to satisfy the tests and requirements of this section and §250.423.

Casing design programs based on the use of liners and sub mudline casing hangers have been used throughout the world for many years and are an accepted industry practice. However, the practice of using a shallow liner hung off within a sub mudline casing hanger merits further review to ensure that this practice is acceptable from a risk standpoint based on the issues raised in this report. This assessment is especially important given that wells such as the MP295 may have a long interval of open hole below the liner (7,000 feet) and have the potential for encountering abnormal pressure zones.

RECOMMENDATIONS:

- 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.
- 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.
- 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.

DUAL BARRIER SYSTEM (SEAL & CEMENT COLUMN) PRESSURE TESTING AND EVALUATION

A successful pressure test after a liner is cemented is generally considered to be an indication that the cement job was conducted as planned and adequately isolates the formation. However, QC-FIT believes that the presence of an elastomeric seal upstream of the cement may actually prevent evaluation of the integrity of the cement in the annulus.

The seal assembly and the cement column are currently pressure tested together as a system rather than independently. Therefore, if the system fails the pressure test this means that both barriers have failed (e.g. both the seal and cement failed). On the other hand, if the system passes the pressure test, it only indicates that one of the two barriers is competent and does not demonstrate that both barriers are independently holding the pressure.

The use of seals in sub mudline or liner systems raises some significant design and regulatory concerns. The use of these seals have advantages from a cost stand point since: (1) they increase the likelihood that the system will pass the pressure test, which reduces the need for costly remedial action to address a poor cement job, and (2) they save the operator time by allowing the pressure test of the casing to be performed before the cement has completely cured.

However, the presence of the elastomeric seal introduces an element of design uncertainty in the well containment system since it may help to mask a poor cement job. By allowing operators to continue drilling ahead without being able to verify the integrity of the cement column, this technology might increase the potential risk in subsequent drilling operations. Further analysis is needed to completely assess these potential risks.

RECOMMENDATION:

- BSEE should conduct an engineering design analysis of standard industry practices related to liners and sub mudline seals and cementing to address the issues listed below:
  - 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?
  - Is the seal or the cement considered to be the primary barrier?
  - 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?
  - 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 mudline 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? Current BSEE requirement is a positive pressure test on conductor and surface strings.
  - 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?
  - 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.

SUMMARY OF RECOMMENDATIONS

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 API RP 19LH to determine whether these documents

provide adequate guidelines for the design and qualification of this equipment.

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.
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.
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.
5. Industry standards should provide sufficient guidelines for ensuring that seal systems are adequately designed and tested pursuant to standardized protocols.
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.
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.
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.
9. BSEE should conduct an engineering design analysis of standard industry practices related to liners and sub mudline 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?
    b. Is the seal or the cement considered to be the primary barrier?
    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?
    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 mudline 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.)
    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?

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.

APPENDIX

TERMINOLOGY

A liner is a casing string that does not extend to the top of the wellbore (i.e. does not extend to the wellhead). It is suspended from a previous casing string, by way of a liner hanger. Therefore, a liner hanger differs from a casing hanger, in that casing hangers are hung off directly from the wellhead and liners are hung off casing strings via a liner hanger. A mudline suspension system is an option for a bottom-supported rig (e.g. jack-up) using a surface BOP, as in the case of this loss of well control event, in order to transfer the weight of the well to the seabed. When using mudline suspension equipment, mudline (or sub mudline, if referring to equipment below the mudline) casing hangers are used to provide suspension points for additional intermediate casing strings that cannot be accommodated by a standard conductor or wellhead housing (as described in API 17D). An annulus seal assembly is a mechanism that provides pressure isolation between each casing hanger and the wellhead housing (also described in API 17D).

In the case of this loss of well control event, the sub mudline casing hanger was hung off of the wellhead, as part of the mudline suspension equipment system. The liner (referred to as a "shallow" liner, because it was hung off at a relatively shallow depth of approximately 703 feet below the mudline) was hung off of the sub mudline casing hanger. The seal assembly in question was at the interface where the shallow liner is hung off of the sub mudline casing hanger (also referred to as the liner top). The shallow liner is also the surface casing in this case. See Figure 1 for a schematic of the sub mudline casing hanger seal used on this well.

FIGURES

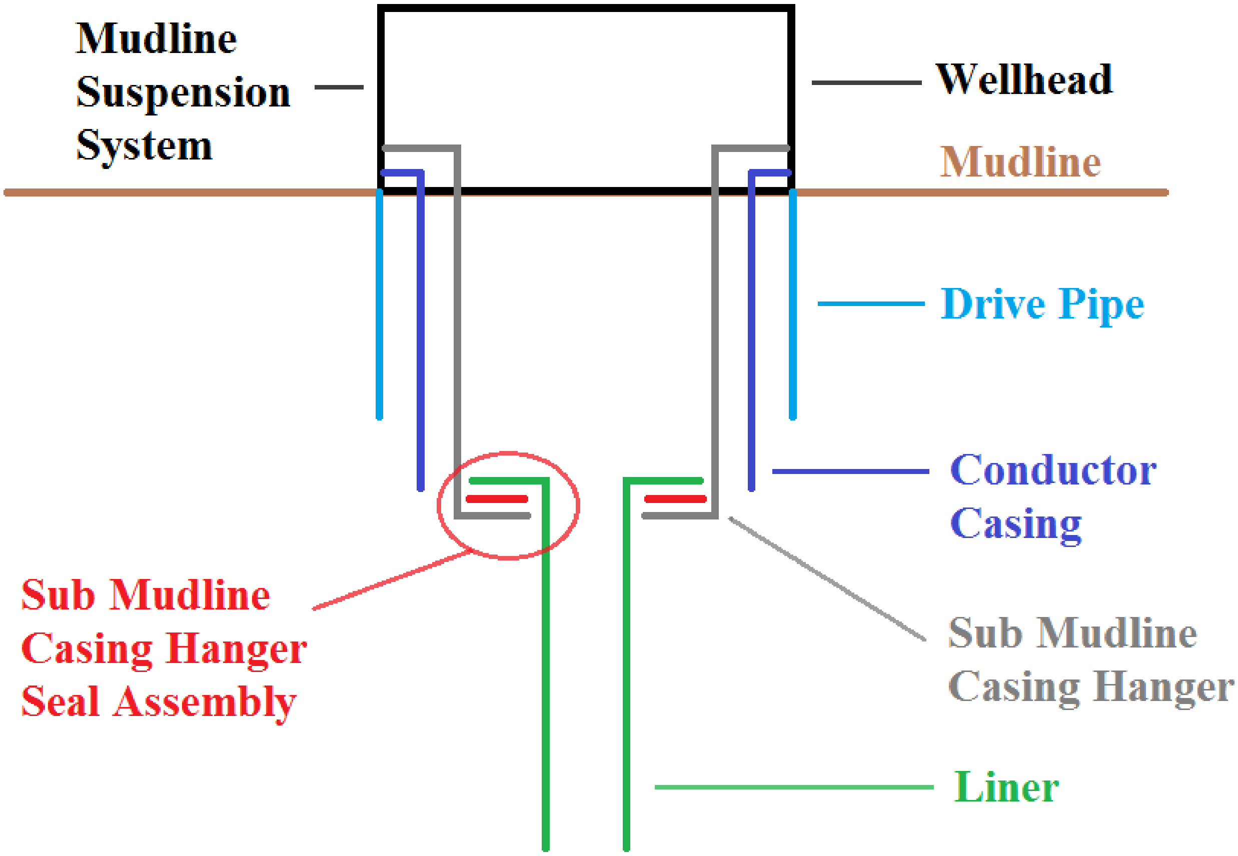

FIGURE 1: SCHEMATIC OF SUB MUDLINE CASING HANGER SEAL ASSEMBLY LOCATION

FIGURE 2: PULLED SUB MUDLINE CASING HANGER SEAL

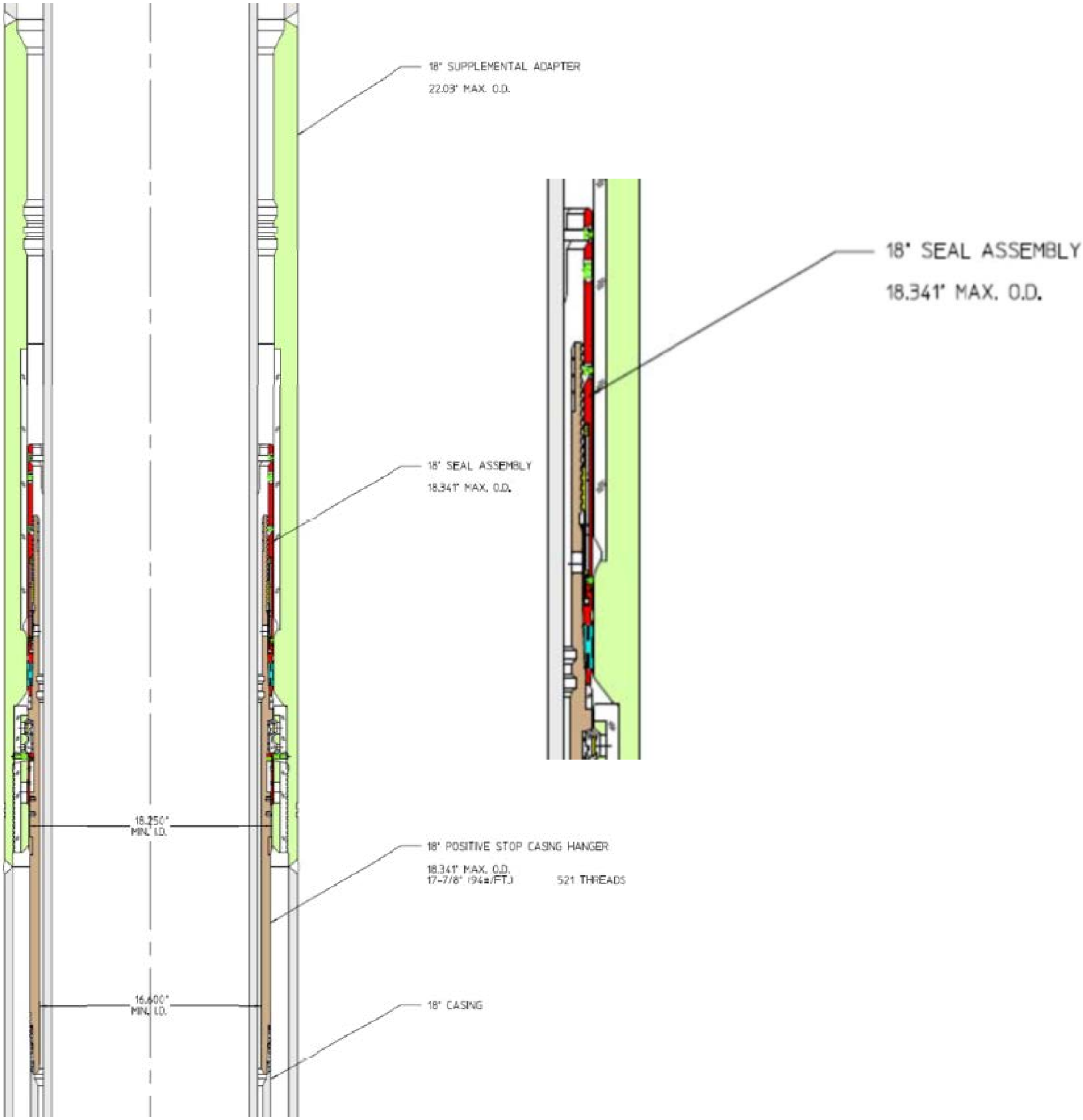

FIGURE 3: SEAL ASSEMBLY SCHEMATIC

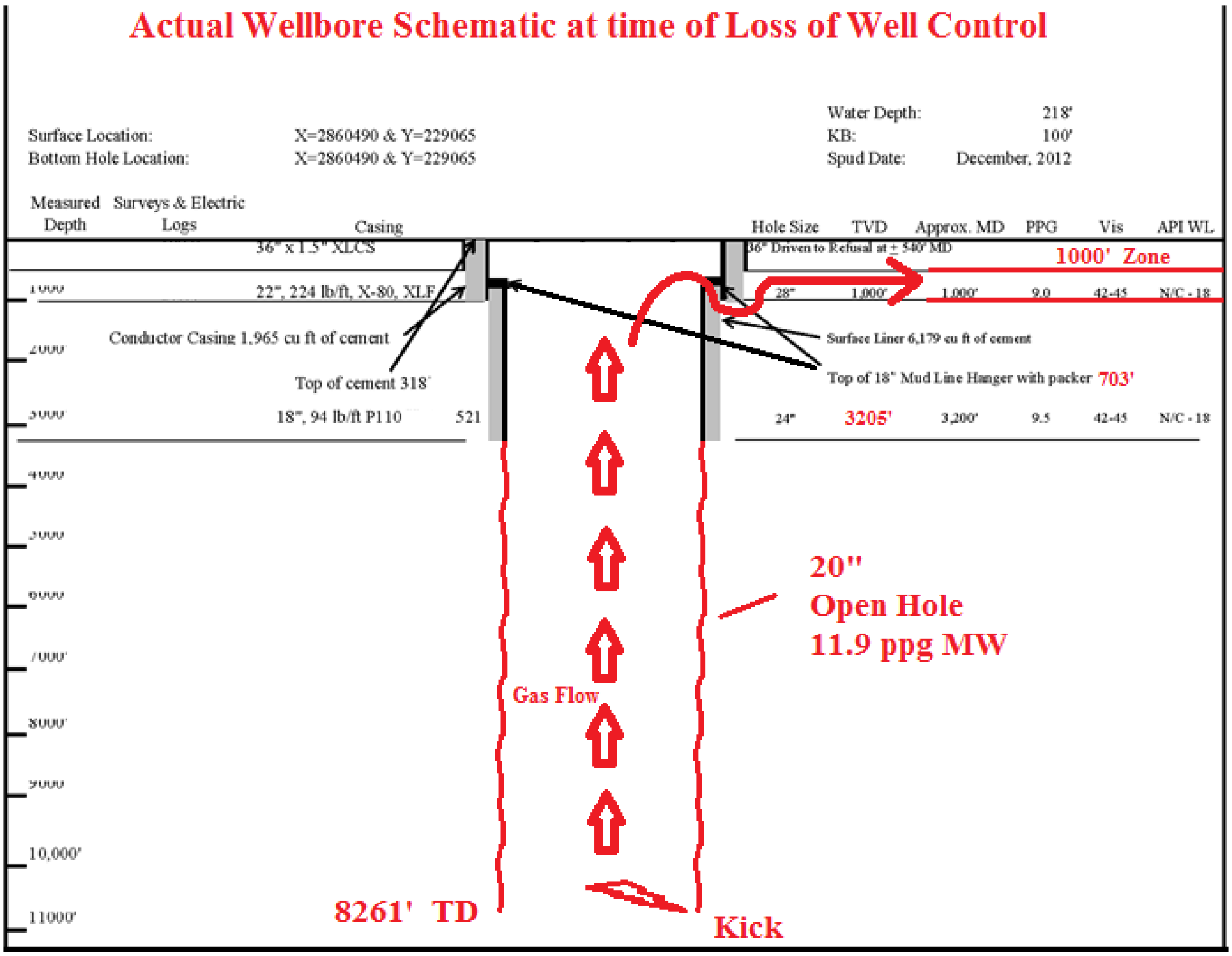

FIGURE 4: ACTUAL WELLBORE SCHEMATIC AT TIME OF LOSS OF WELL CONTROL[8]

[8] Figure 4 shows a possible flow path up the wellbore and into the formation via the seal. Other possible flow paths include damaged casing, leaking threaded connection, and flow around the 18 inch shoe. It is not known which of these flow paths the gas took. The fact that there were multiple possible paths for the gas to flow is indicative of an industry wide issue concerning the dual barrier seal and cement system.

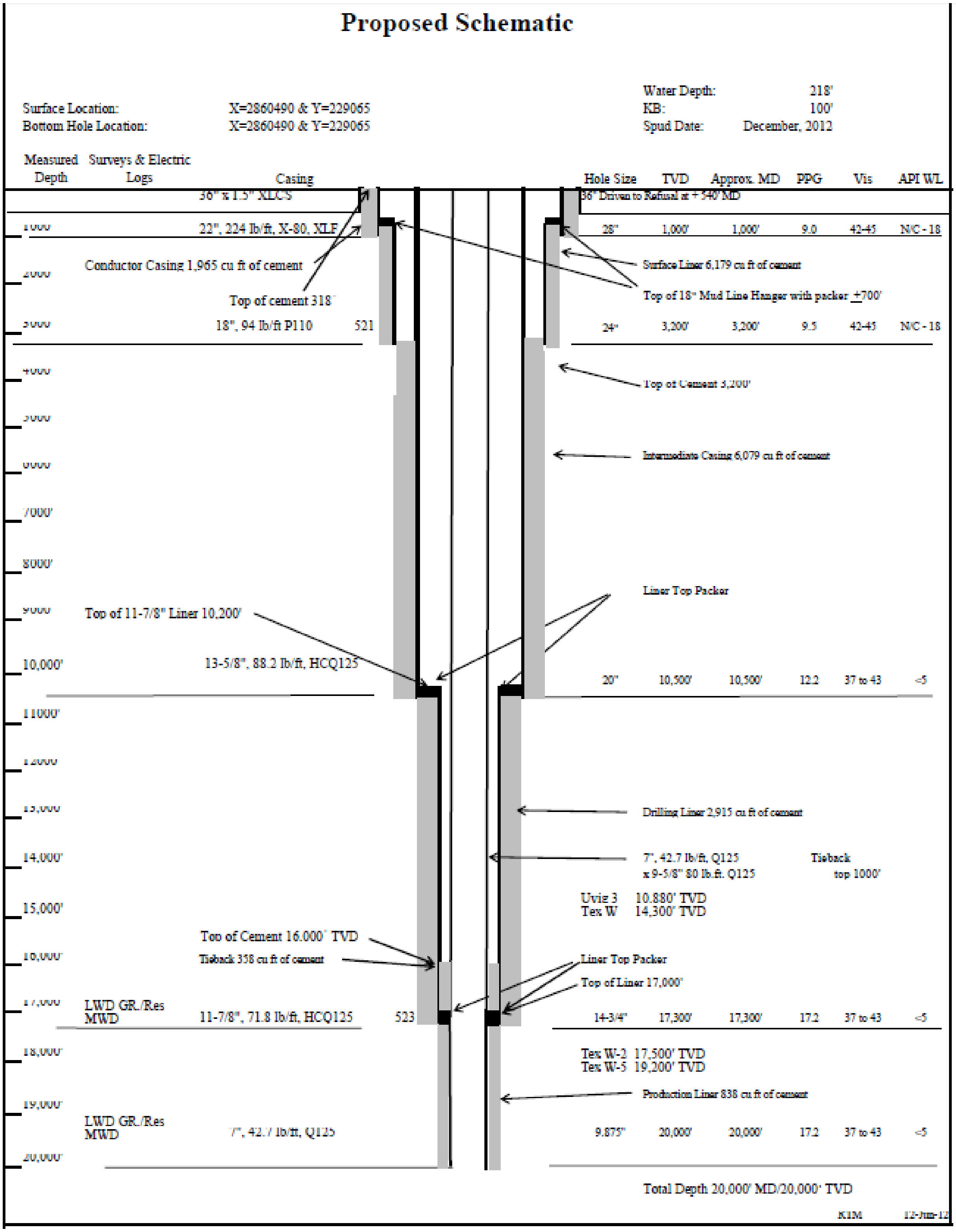

FIGURE 5: PROPOSED WELLBORE SCHEMATIC