MC 20 Response Task 8 and Task 9 Report

Document #: Couv-Proj-Rpt-00031

DATE

12/10/2019

This study was funded by the US Department of the Interior, Bureau of Safety and Environmental Enforcement through Interagency Agreement E19PG00018 with the United States Coast Guard.

Revision	Date	By	Check	Approve	Remarks
Rev Red	1/7/2019	Couvillion Group	D. Hoffmann	T. Couvillion	Initial Document

CONTENTS

LIST OF FIGURES

LIST OF TABLES

1.0 EXECUTIVE SUMMARY

This report contains the results of a review of available site information (data, reports and studies) to support long-term sub-surface source control operations at the Mississippi Canyon Block 20 (MC 20) Taylor Energy site. Key findings, data gaps and closure plans along with recommendations to secure the sources and/or achieve plugging and abandonment standards are contained in this report.

Findings:

There were four key findings:

1) Oil and Gas is flowing from sub-surface source to the surface
2) The field and all reservoirs have the potential to flow
3) All wells have multiple integrity issues leading to multiple potential leak paths
4) None of the 25 active wells at the time of the incident have been abandoned per Bureau of Safety and Environmental Enforcement (BSEE) Well Abandonment Standard 30 Code of Federal Regulations (CFR) 250-1715

Data Gaps:

Gaps in the site information were identified and recommended for closure, (see Section 5.0).

Recommendation:

Based on the findings and research to date, it is recommended that every effort is made to abandon all wells at the MC 20 site per 30 CFR 250-1715 Well Abandonment Standard. It is also recommended to go beyond the standard, if possible, by achieving zonal isolation in the sections above the upper hydrocarbon bearing sands that have the potential for flow of oil and gas to the surface. The work done by Firms with Industry Specific Technical Experience (FISTE) and the Project Team have highlighted that source control and/or abandonment can be achieved in a safe and viable manner (See section 4 of this report).

Multiple FISTE and specialists were engaged to evaluate technologies both inside and outside the industry in the market research phase and arrived upon the following options to secure the sources and/or achieve Plugging and Abandonment standards:

- Excavation to Access the Wells and Intervention
- Intercept Wells
- Depletion
- Accelerated Depletion

The combination of deterioration of downhole systems (corrosion/erosion of tubulars, seals, barriers and zonal isolation) with reservoir re-charging will lead to increases in oil discharge rates and/or the creation of additional plumes. Accordingly, it is recommended that action be taken now to plan and execute a program to secure the sources and/or plug and abandon all wells to the standard.

2.0 BACKGROUND & SCOPE OF TASK 8 & 9

In September 2004, the MC 20A platform was toppled by a subsea mudslide that occurred during Hurricane Ivan. The platform was toppled and moved down slope approximately 500 feet. All the well-bay conductors were pulled over and buried under sediment. Of the 28 wells on the platform, 25 wells were active at the time of the incident. From 2009 to 2011, Taylor Energy Company (TEC) attempted interventions on nine wells which were deemed to be the highest risk to flow. After 14 years of monitoring, and failed attempts at subsea containment, oil and gas continued to flow to the surface.

Couvillion Group Limited Liability Company (LLC) was selected to implement containment strategies and tactics that would eliminate the surface sheen at the MC 20 site and to develop long-term plug and abandonment options. Tasks 1 through 7, which have been accomplished, focused on eliminating the surface sheen. This report covers Task 8 and Task 9 objectives, which are to perform a technical review of the **Long-Term Plug and Abandonment Options**.

Link to Task 8 and Task 9 Deliverables

The Rapid Response System is currently operational; capturing, separating, and storing oil from the source in a controlled manner. The containment system is significantly reducing pollution and consequent damage to the environment by capturing oil, but is still releasing vented gas, and reservoir water. The below issues highlight that containment is only a temporary solution.

- While the system is currently capturing the majority of the oil and significantly reducing the sheen; gas, residual oil and water from underground reservoirs continue to spill into the Gulf with intermittent sheening occurring.
- The containment system is subject to risks of mechanical failures, future potential mudslides, and other naturally occurring or manmade events.
- The combination of deterioration of downhole systems (corrosion/erosion of tubulars, seals, barriers and zonal isolation) with reservoir re-charging will lead to increases in oil discharge rates and/or the creation of additional plumes.

This report contains the results of a review of site information (data, reports and studies) to support long-term sub-surface source control operations, recommendations to close data gaps and a review and recommendation of options to secure the source and/or achieve Plugging and Abandonment standards.

Link to Site Information (Data, Reports and Studies) Reviewed

Information was categorized into four categories:

1) The 28 original wells, “A” wells
2) The 9 attempted intercept wells drilled by TEC, “IW” wells
3) Field & reservoir information
4) Studies and reports.

Market research was conducted to identify viable options for sub-surface source control operations including well intervention and/or reservoir depletion to secure the source and/or achieve plugging and abandonment standards.

The TEC MC 20 Final Risk Assessment and Cost Estimate report (FRACE) was issued in 2014. The FRACE report gives the impression of presenting a series of conclusions, findings and recommended way forward on behalf of the Unified Command surrounding the MC 20 event and its after effects. The key findings of this Task 8 and 9 report are not aligned with many conclusions in the FRACE report and support an alternative series of recommendations for source control and/or long-term abandonment options.

The team found the FRACE report to contain biases, especially in many assertions that are not supported by the underlying data. There are conclusions in the FRACE report that have used assumptions or a series of assumptions that are viewed as beyond reasonable. There are other instances in the FRACE report where assertions and conclusions are factually incorrect. Section 7 of this report highlights some of these key inconsistencies.

Link to FRACE report section

3.0 FINDINGS

3.1 OIL & GAS IS FLOWING FROM SUBSURFACE SOURCE TO SURFACE

- Volume of Oil being collected at site by Task 8 and 9 Interagency Work Group since April 12th, 2019.

The Couvillion Group LLC was contracted by the United States Coast Guard (USCG) to design, build, install and operate a Rapid Response System to capture the ongoing release of oil that had been causing a sheen on the ocean surface for the past 14+ years. The system consists of a containment device (a porch that is held in place by the downed platform jacket and a shallow dome located approximately 5' off the seabed), a patented 3-phase subsea separator and oil storage containers located on the jacket at a depth of approximately 400 ft. The system allows for hydrocarbon gas to flow back into the seawater at the separator and for produced water and seawater to flow out the bottom of the separator. Oil is separated out in the separator and flows into the oil storage containers. As oil flows into the oil storage containers, seawater is displaced out of the four-inch valves and hoses at the bottom of the oil storage containers. On a periodic basis (3 to 5 weeks) the oil collected in the subsea oil storage containers is pumped to a surface vessel using a submersible hydraulic pump. The surface vessel contains processing equipment to remove residual water and entrained gas. The oil is taken back to shore for recycling.

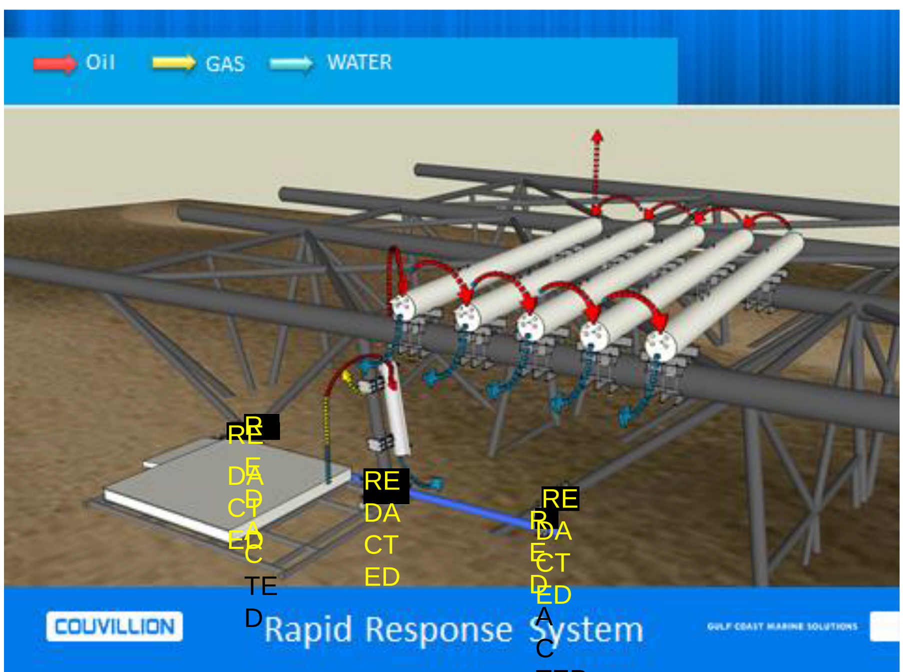

Figure 1. Rapid Response System

Work commenced on November 19th, 2018 and on April 12, 2019, the system began collecting oil. The system continues to collect oil. There have now been eight trips thus far to the MC 20 site to collect and reprocess the captured oil. Detailed results of these pump-offs can be viewed in the Oil Volume Talley document linked below. During this time period (April 12, 2019 to October 23, 2019) there have been 236,038.3 gallons (5,620 barrels) of fluid collected netting out 201,782.7 gallons (4,804 barrels) of crude oil. This equates to a crude oil capture rate of approximately 1,000 – 1,300 gallons/day.

- *MC 20 Product Removal and Transportation Plan*
- *Oil Volume Tally*

- Hydrocarbon sheen at surface over time

Visual evidence of hydrocarbons flowing from the sub-surface reservoirs source to the surface has been observed since the incident occurred in 2004. Photos of the site and associated sheen are shown below before and after the containment system was installed in April of 2019. The oil flowing at a rate of between 1000 and 1300 gallons per day into the containment system has been analyzed and has been determined to be coming from multiple wells at the MC 20 site.

Figure 2. 2016 Sheen Sample Before Containment System

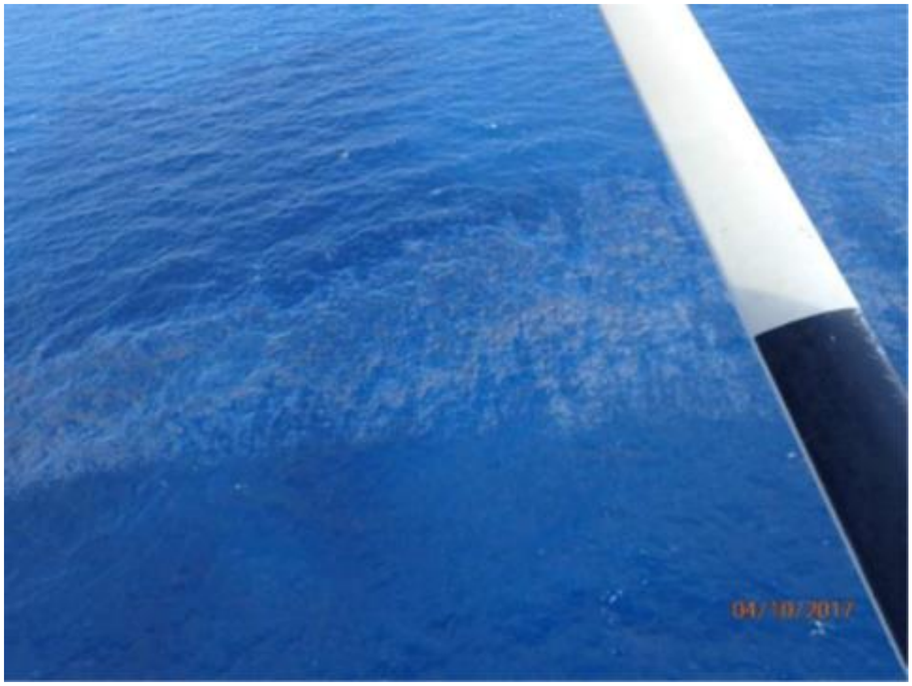

Figure 3. 2017 Sheen Sample Before Containment System

Figure 4. 2018 Sheen Sample Before Containment System

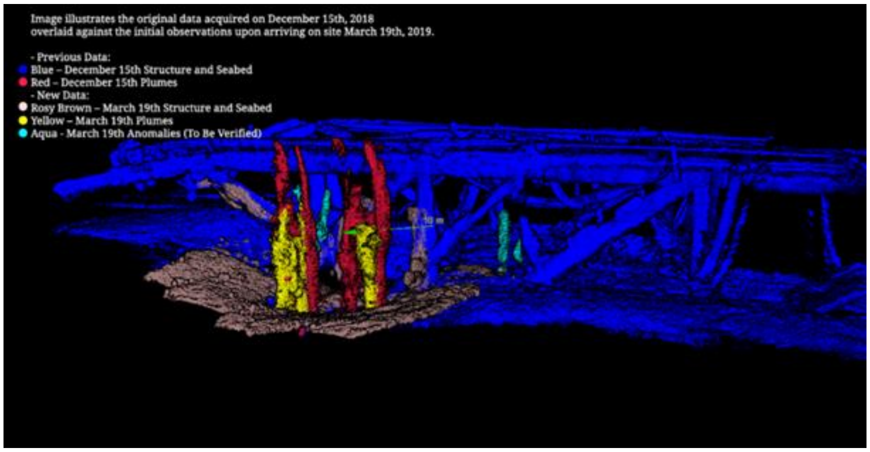

Figure 5. Echo Scope Image Showing Hydrocarbon Plumes at Platform on Seafloor in December 2018 (red) and Then in March 2019 (Yellow). Note: Containment & Collection System Not Yet in Place

Figure 6. February 23, 2019 First Day on Site Prior to Starting Installation of the Rapid Response System

Figure 7. April 16, 2019 Testing and Adjustments on Rapid Response System After Installation on April 12, 2019

After Containment System in Place and Fully Operational:

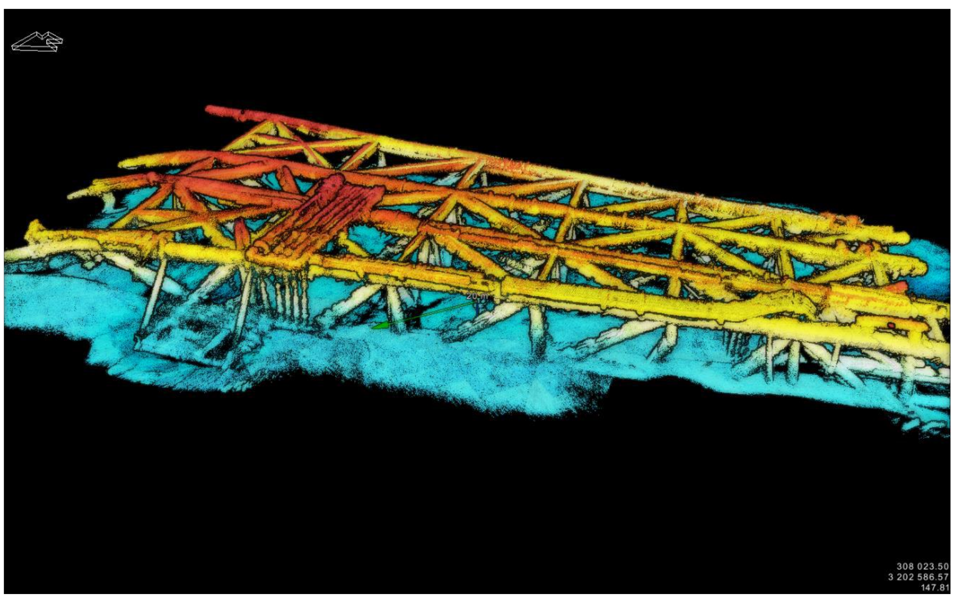

Figure 8. Echo Scope Image Showing Plumes are Contained by Rapid Response System as Opposed to Figure 5 Clearly Showing Hydrocarbon Plumes Flowing into the Gulf

Figure 9. May 21, 2019 MC 20 Site after Containment, Capture and Storage System Operating for About 1 Month

Figure 10. June 14, 2019 MC 20 Site after Containment, Capture and Storage System Operating for about 2 Months

Figure 11. Aug. 05, 2019 MC 20 Site after Containment, Capture and Storage System Operating for about 4 Months

Figure 12. Sept. 03, 2019 MC 20 Site after Containment, Capture and Storage System Operating for about 5 Months

Photos of site above are monthly images which are representative of Southern sea plane overflights. Links to file containing sheen photos over time.

- *MC 20 Historical Monthly Over-flights*

Taylor Energy Company's oil spill reports to the National Response Center, the NOAA NESDIS Marine Pollution Surveillance Reports and Skytruth all report on the MC 20 site oil spill. The data from these reports are shown in graphical form below. All three reports show that there was a dramatic reduction in volume of oil reported and area of sheen reduction when the Rapid Response Solution was installed and became operational.

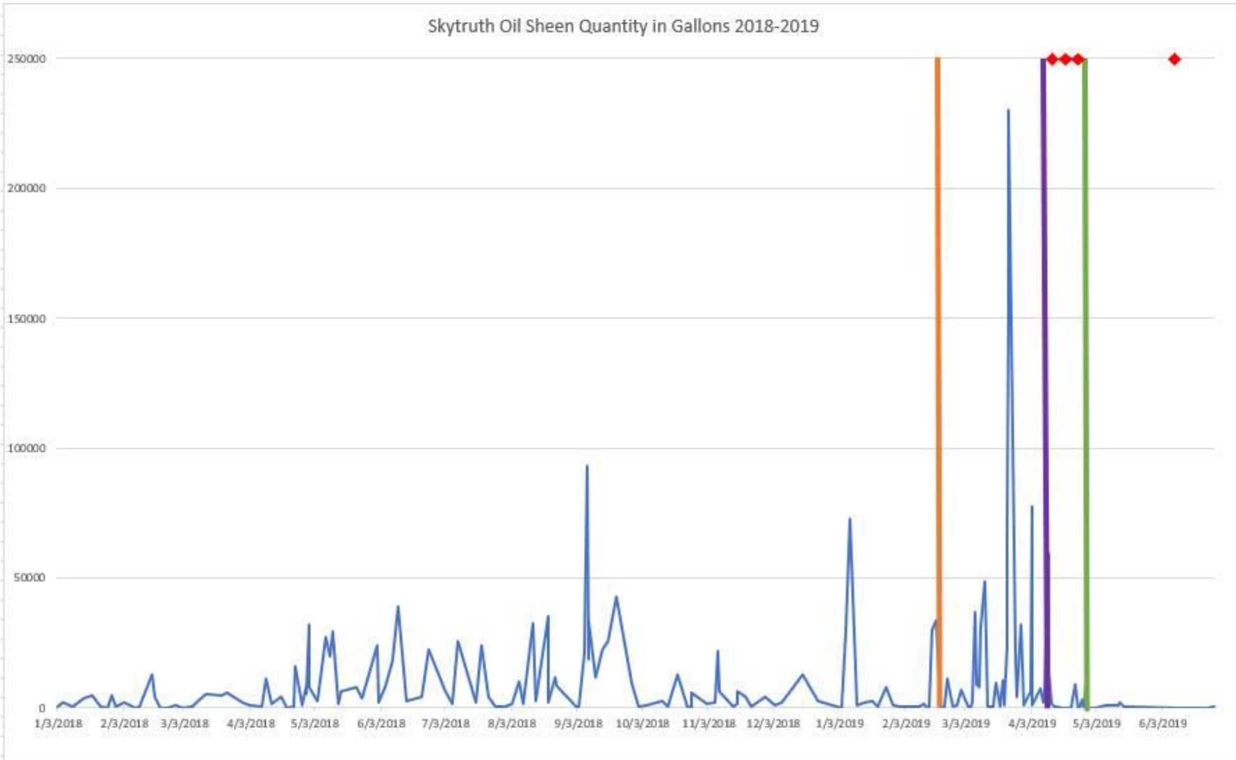

Figure 13. Oil Collected from Rapid Response Solution

The figure has color coded vertical lines installed indicating the date the installation vessel arrived on site (orange), indicating the day the Rapid Response Solution started collecting oil (purple) and the day when the Rapid Response Solution was complete and fully operational (green). Dates of the pump offs are also shown as diamonds in red at the top right portion of the graphs. The above data confirms that the Rapid Response Solution's stationary dome is collecting virtually all of the oil subsea and that the source of the MC 20 spill emanates from a specific fixed location or "pit" beneath the dome from which the plumes are flowing and have been identified to contain oil, gas and produced water.

- Indications of minor sheens after containment installed.

Since April 12, 2019 the Rapid Response Solution has been successfully collecting oil subsea to stop the sheen at MC 20. There are days, however, where a slight sheen is observed on the surface of the water in and around the MC 20 site. While the sheen observed is significantly smaller than sheens observed before the Rapid Response Solution was deployed the question was asked: Could the gas being vented from the subsea separator contain enough lighter-end hydrocarbons to cause a sheen on the surface of the water? To address this issue two gas samples were collected at the gas separator outlet subsea at a water depth of 404-405 ft and temperature of approximately 65F using two 80 cubic ft scuba tanks that had been modified for gas collection. One sample was placed on the bottom of a 1,000 gallon tank filled with fresh water. The valves were then opened slowly to allow the gas to be vented to the surface. A very slight sheen was observed.

The second sample of gas was sent to Core Labs for chemical analysis. From the gas composition that was analyzed a GPM (gallons per 1,000 scf/day gas) value of 1.457 gallons of plant products per 1,000 cubic feet of gas at standard conditions of 15.025 psia and 60 °F has been calculated. This GPM value is calculated based on molar contributions from ethane out to what we are defining as C10+. Eliminating the very volatile components from the GPM calculation and starting the GPM calculation at iso-pentane, the resulting GPM value would be 0.061 gallons per 1,000 scf. So, for every 1,000 scf of gas produced, we could potentially generate about 0.061 gallons of hydrocarbon liquid. For the quantity of gas contained within one of the scuba tanks this would equate to one liquid hydrocarbon droplet of 1.467 cm in diameter which would explain the very slight sheen observed in the 1,000 gallon tank test.

This testing indicated that gas being vented from the subsea separator could contain enough lighter-end hydrocarbons to cause a sheen on the surface of the water. A full report documenting these tests are shown in the following link.

Link to Oil Sheen Analysis Test and Gas Compositional Analysis

- Oil and gas plumes at sea floor.

  Oil and gas plumes documented at the MC 20 location from 2006 through 2019 confirm the presence of hydrocarbons flowing to the surface from MC 20 wells.

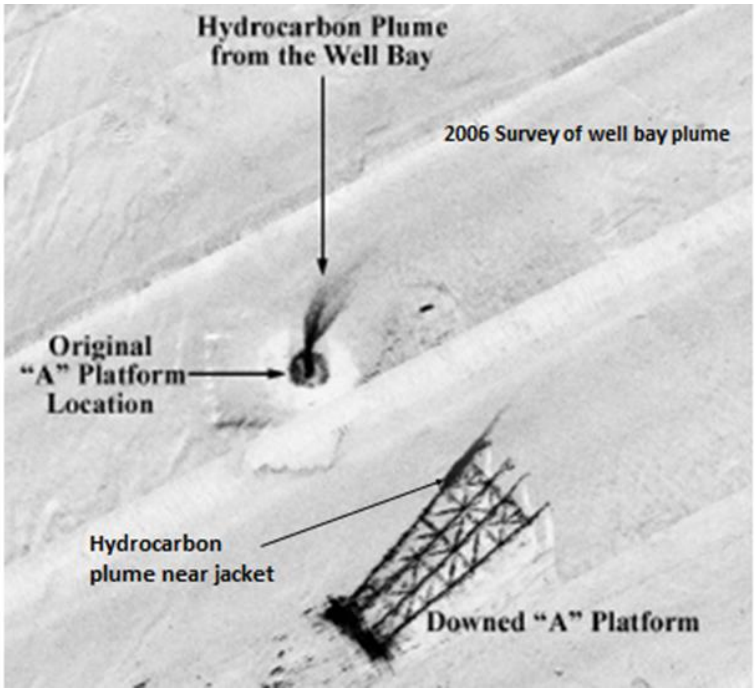

Figure 14. 2006 Survey of Well Bay Plume

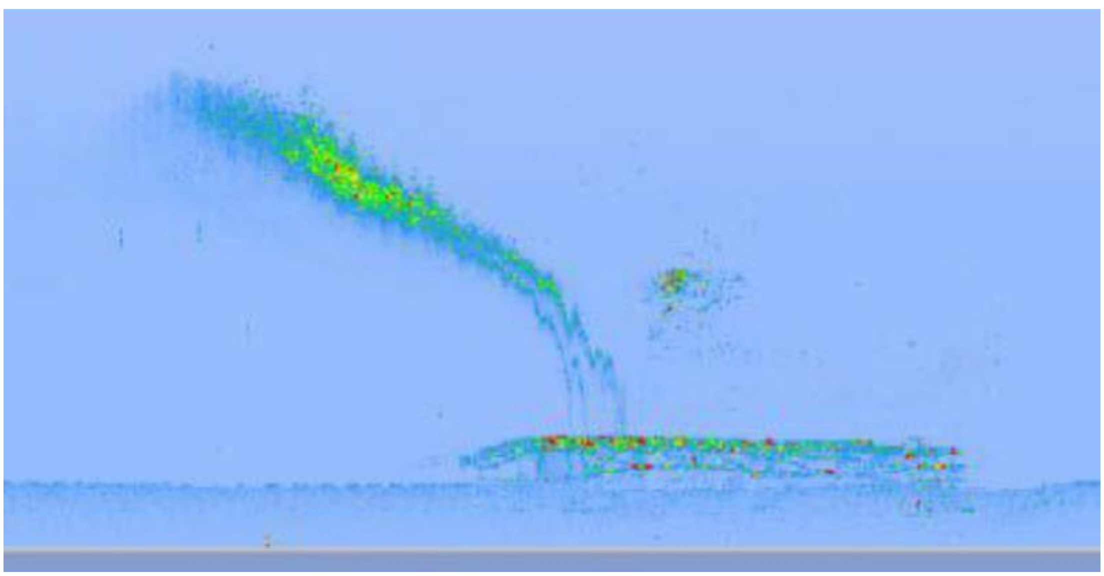

Figure 15. 2012 Plume image from downed jacket site.

See Figure 5 (2018) and Figure 8 (2019) for additional plume images.

- Analysis of hydrocarbons collected at MC 20 site.

Samples were taken, analyzed and compared from the surface sheens, bottom plumes (oil, gas & water), and offtake collection of crude oil from the Rapid Response System and comparisons were made to samples from 1984 MC 20 A2 and A9 wells.

- The analysis of hydrocarbon samples taken from MC 20 site show that the hydrocarbons are coming from multiple MC 20 wells.

- Analysis of the hydrocarbon gas samples reveal that the samples are predominantly Thermogenic gas (i.e. from reservoir) and not biogenic as asserted by Taylor.

Link / Reference to 2018 Sample Analysis Reports

- *NOAA Integrated Assessment of Oil and Gas into Environment at MC 20 Site*
- *Newfields Letter Report – TEC Off-load Oils April 302019*

3.2 POTENTIAL TO FLOW

The reservoirs and sands of concern in the MC 20 field have the potential to flow hydrocarbons from the subsurface source into the environment.

- Oil and Gas is flowing from Subsurface Sources to the Sea Floor and is being collected by the Rapid Response System (See Finding #1)
- Modeling – Four different models were used to evaluate the field and reservoirs for potential to flow. The models are categorized by:

    - **Category 1: Models assuming integrity**, i.e. only the perforated interval at the time of the incident can flow through a given well. The tubulars, packers, seals, and cement, etc. do not have leak paths.

        a. **The Nodal analysis model**: This analysis model (used in the FRACE report) couples an inflow model from the reservoir into the bottom of the well and a tubing flow performance model. This was the type of model used by Cobb and Associates and later by Platt-Sparks and Associates to define the list of 9 wells with the highest potential to flow. See Case 1A in table below and Figure 16 and Figure 17.

b. **<u>The “driller’s” hydrostatic head model:</u>** If the pressure of the perforated interval after recharge is above the pressure exerted by a column of sea water in a well, then it has potential to flow. **Under this model, 16 wells and 14 sands have the potential to flow.** See Case 1B in table below.

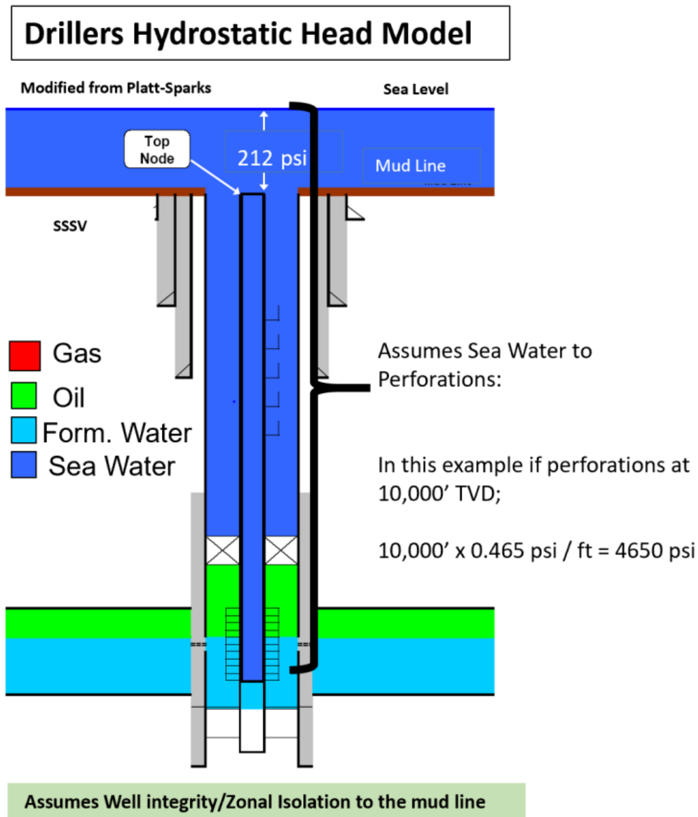

Figure 16. Drillers Hydrostatic Head Model

c. **<u>The "modified" head model:</u>** This model replaces the hydrocarbon column above the mudline with seawater. This head pressure is compared with the estimated reservoir pressure after recharge. **This model shows 20 wells and 16 sands have the potential to flow.** See Case 1C in table below.

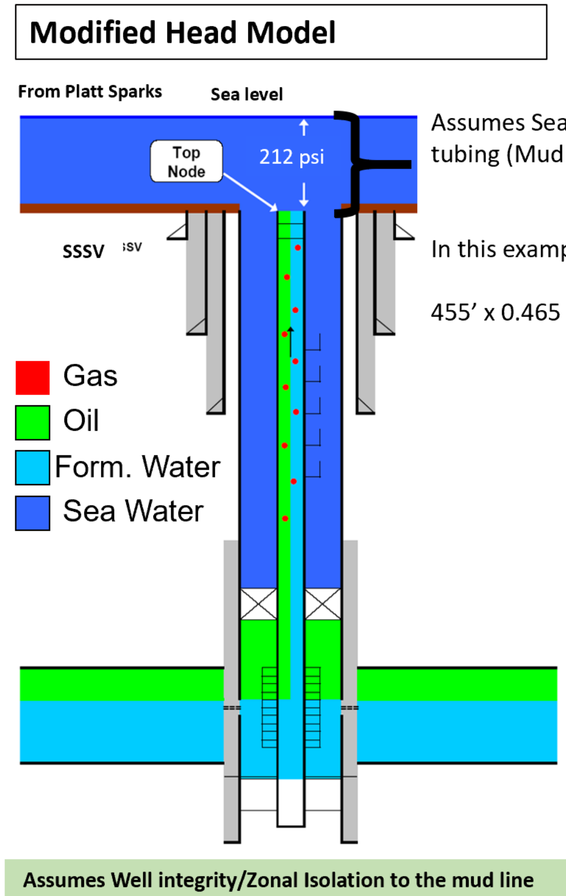

Figure 17. Modified Head Model

In models B and C, a range of +/- 10% was applied to the <u>Recharge Pressure for the Producing Reservoirs</u> (due to aquifer inflow) estimated by Cobb and Associates.

- **Category 2: Considers a loss of integrity**; paths of flow due to cement, tubulars, seals, packers, valves and/or other barrier failures. See Finding # 3 Well Integrity. In this case, all hydrocarbon sands behind casing, above hydrostatic pressure are considered as a potential source of leakage. This applies to:

    - Shallow (not produced) hydrocarbon bearing sands
    - Thin “non- commercial” hydrocarbon sands within the produced reservoir stack
    - Pressure recharged sands above hydrostatic not perforated in a particular well but present behind its casing

Under this scenario ALL WELLS in MC 20 have Potential to Flow. (See Case 2 in table below)

Table 1. Modeling Table

MC-20 POTENTIAL TO FLOW - COLUMN HEAD ESTIMATES- SEA WATER and LAST FLOWING MIX

				Assuming Well Integrity			
Reservoir	**Completion**	**Status at Ivan**	**Reservoir Fluid**	**Case 1 A FRACE Nodal Analysis Model**	**Case 1 B Driller's Hydrostatic Head Model**	**Case 1 C Modified Head Model**	**Case 2 (*) Catastrophic Loss of Well Integrity**
F R20-1	A-17	ON	DRY GAS	YES	YES	YES	
H RA-2	A-13	SI/DX	GAS+OIL RIM	YES	YES	YES	
I RB	A-24	ON	OIL		-	-	
I RD	A-21	ON	OIL	YES	YES	YES	
I RE	A-19ST	ON	OIL	YES	YES	YES	
I RF	A-22	ON	OIL		-	-	
J RA	A-09ST	ON	OIL		-	YES	
J R20-1	A-03	SI	OIL+ GCAP		YES	YES	
J R20-1	A-08	SI/DX	OIL+ GCAP		YES	YES	
K RA	A-11	ON	GAS	YES	YES	YES	
K RG	A-20	ON	OIL		-	YES	
L R20-1	A-01	ON	OIL+ GCAP	YES	YES	YES	
L R20-1	A-12D	SI/DX	OIL+ GCAP		YES	YES	
L RA	A-14ST	SI	OIL		-	YES	Potential to Flow
L RG	A-25	ON	OIL+ GCAP		-	-	
L RG	A-26	ON	OIL+ GCAP		-	-	
L1 RC	A-07ST	SI	OIL		-	-	
L3 RA-2	A-02	ON	OIL+ GCAP		YES	YES	
L3 RA-2	A-10	ON	OIL+ GCAP	YES	YES	YES	
L3 RA-2	A-18	SI	OIL+ GCAP		YES	YES	
L1 RA2	~~A-01~~	X	No info.		-	-	
L3 RH	A-28	SI	DRY GAS		YES	YES	
M R20-1	A-04	ON	OIL	YES	YES	YES	
M R20-1	A-16D	ON	OIL	YES	YES	YES	
M1 RA	A-23	ON	GAS		-	YES	
M1 RG	~~A-26~~	X	No info.		-	-	
NR 20-1	A-06	ON	OIL+ GCAP		YES	YES	
NR 20-1	A-12	SI/DX	OIL+ GCAP		YES	YES	
	WELL Count (**)			9	16	20	25

(*) In Case 2 There is Potential to Flow from every HC sand Not just the sand being produced at time of incident

(**) Dual Completion in A-12 counted as a single WELL

Category 2 (the loss of integrity model) is the most realistic model supported by:

- All initial (pre-production) hydrocarbon pressures in MC 20, for all sands/reservoirs were reported above hydrostatic
- The cement bond quality of the wells prior to the incident is reported as good only in limited spots in some wells and in many cases is unknown and/or poor quality
- The presence of an active discharge while all wells were equipped with subsurface safety valves, which if self-actuating per design, should have closed the tubing to flow in all cases
- It is common to have strong indications of communication behind casing between producing and not perforated intervals, in mature producing wells within stacked reservoirs fields
- Well Integrity issues, Finding #3 in this report

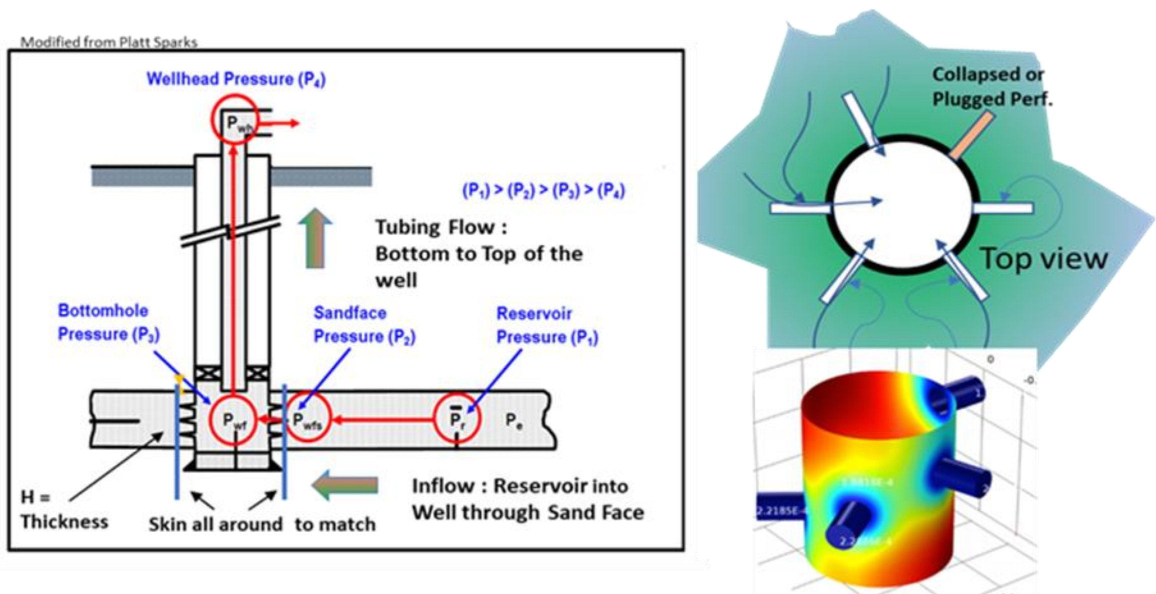

Figure 18. Well flow to surface is drive by Pressure Differentials.

In Nodal Analysis:

On the left side in Figure 15; wells flow when Reservoir Inflow = Tubing flow (all other imposed conditions being met). Flowing bottom hole pressure (Pwf) is the link balancing the two separate calculations for inflow and up the tubing flow. A skin factor affecting only the inflow piece is commonly used to represent “damage” to the well/reservoir connection. The larger the skin the more damage; and the less inflow. There are other assumptions used in the model such as: homogeneity of the reservoir, radial inflow through the whole perforated interval flow.

On the right side in Figure 15; Top view and 3D side view to the right try to illustrate the complexities of near well inflow, due in part to rock heterogeneities (at the scale of the separation between perforations) and the complexities of the perforation process itself.

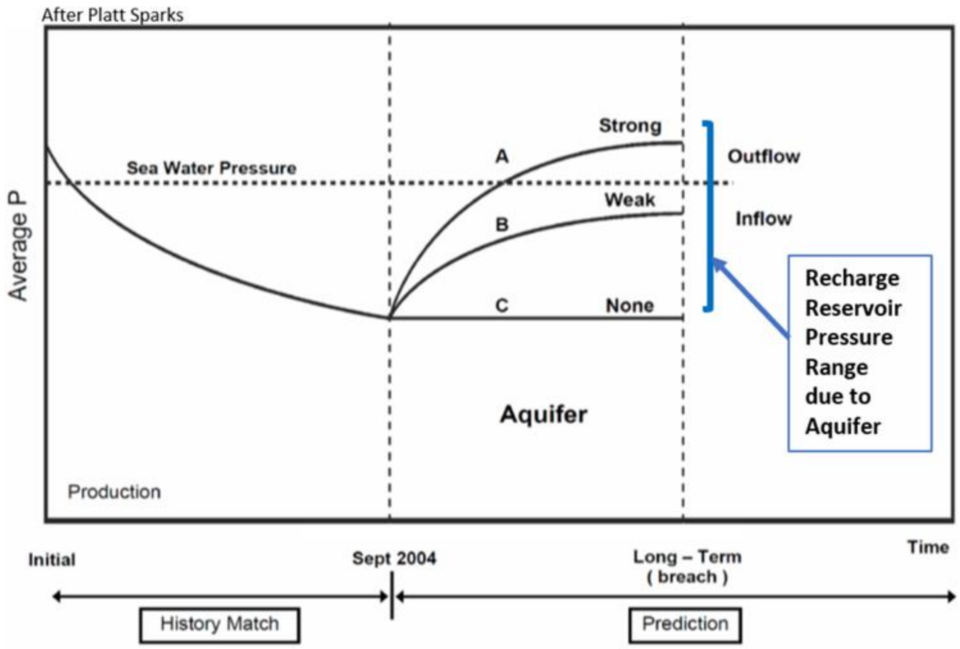

Figure 19. From Platt-Sparks Report. An active aquifer will increase the reservoir pressure over time, at low or zero offtake rates, as is the case in many of the MC 20 field reservoirs.

Nodal Analysis Methodology Sensitivity

The FRACE report conducted Material Balance Reservoir Recharge Pressure analysis with MBAL and a well by well Potential to Flow analysis with Prosper (Oil & Gas Reservoir Modeling Software). Based on this work FRACE concluded that 9 wells had the potential to flow.

The nodal analysis used in the FRACE report is standard methodology for commercial wells in producing fields, however when applied to the post-incident situation in MC 20 it fails to recognize loss of well integrity and zonal isolation which results in all sands and wells having the potential to flow. (See Finding #3 in this report).

Additionally, there are some weaknesses in how the methodology was applied post-incident which would result in additional wells having the potential to flow. The methodology and analysis:

Did not take full account of the sensitivities in key inputs, for example;

- Reservoir Recharge Pressure (some analysis done by Platt Sparks for FRACE was left out)

- Tubing Flow Correlation and other parameters like Completion Inflow Skin
- Historical rate allocation and fluid flow ratios (Gas, Oil & Water)

Made over simplistic assumptions regarding;
- Homogeneity of reservoir
- Water encroachment behavior
- Steady state flow, completion skin and flowing completed interval

Moreover, the clear possibility that Nodal Analysis as applied, may just not be valid for a low rate uncontrolled flow situation, is also discussed. A linked section is dedicated to showing through a few examples how tweaking sensitivities of some key inputs, and/or applying more realistic views of some over-simplifying assumptions, it is relatively easy to modify the results in FRACE.

Link to Potential to Flow Sensitivity Examples

3.3 WELL INTEGRITY

All MC 20 wells have integrity issues leading to multiple potential leak paths.

The below graphic combines the Potential to Flow finding with this Well Integrity finding. Simply stated; all sands have the potential to flow reservoir fluid through or around the wells (conduits) via any of the multiple leak paths of the wellbore to the surface.

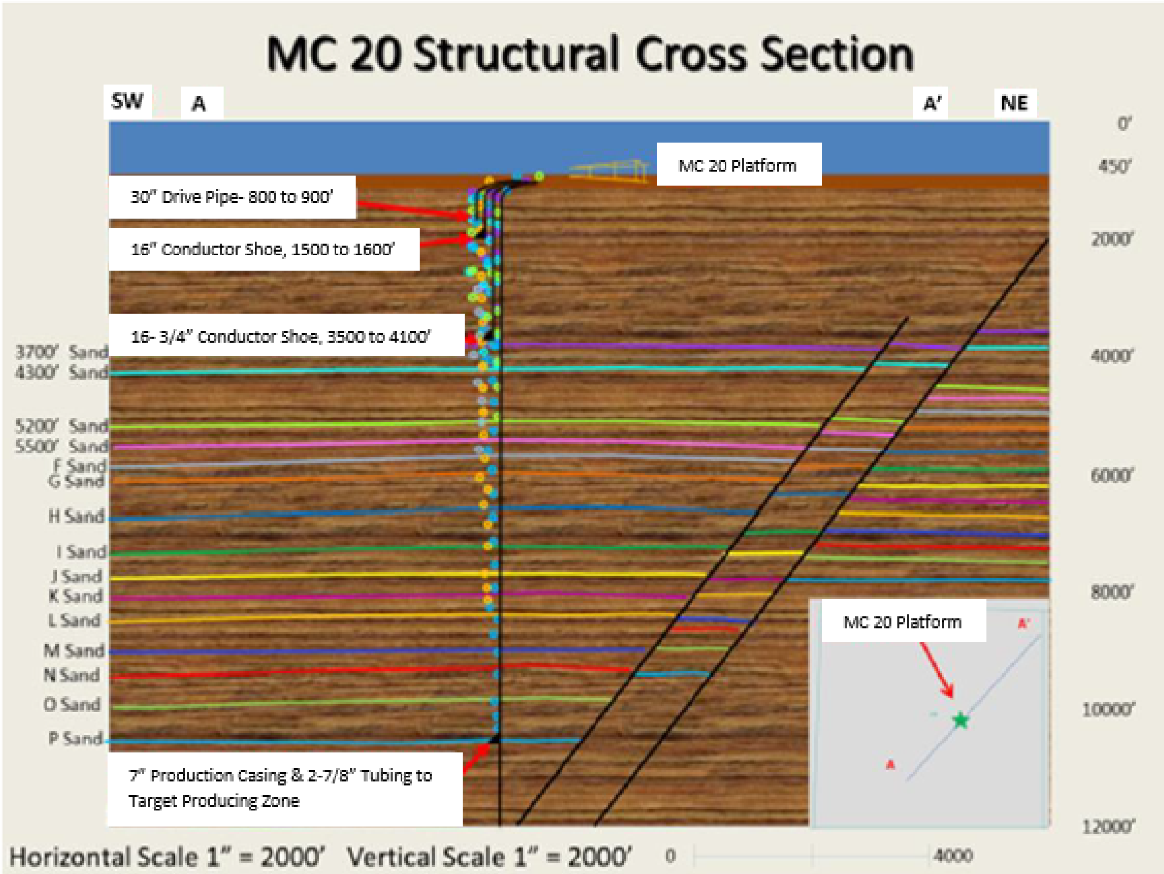

Figure 20. MC 20 Structural Cross Section

The fact that the Rapid Response System is collecting 1000 to 1300 gallons of oil a day from subsurface sources demonstrates that multiple wells have integrity issues. Reference finding #1 in this report.

- Integrity of MC 20 Wells prior to the 2004 incident

  Figure 18 depicts a generic MC 20 well production tree, tubing spool, casing spool, and wellhead section. This design is typical of a surface stack production tree/wellhead design that is being used successfully today on offshore wells, inland water wells, and land wells throughout the oil & gas industry.

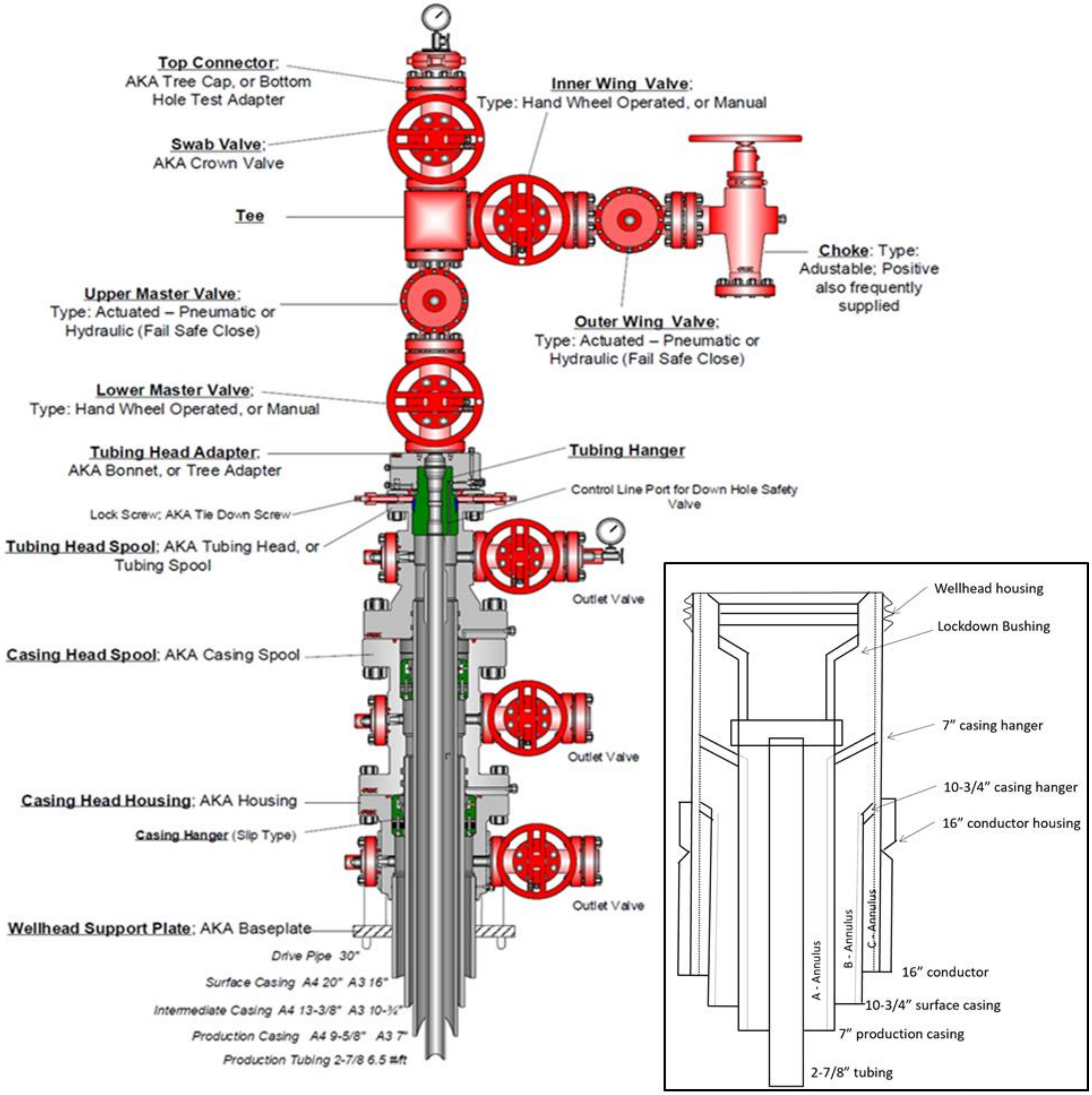

Figure 21. Wellhead and Tree

When well components are functioning properly under normal operations there should not be any pressure on the annular spaces. If pressure is detected in an annular space, this is an indication of an integrity issue which is typically due to a leak path with a source that has higher pressure than the fluid column in that annulus. While casing pressure in the A annulus can sometimes be induced by gas lift, this explanation is not definitive as there are possibilities of packer, tubing, casing and/or other barrier failures. Pressure on the B and C section annuli in a well with integrity cannot be explained by gas lift. This indicates well integrity issues. Wells on gas lift are often capable of flowing as gas lift is used as a means to accelerate production rate, i.e. just because a well is on gas lift does not mean it cannot flow on its own.

Cross referencing the TEC report from August 2004 and a separate BSEE report shows that 22 of the 25 wells had casing pressure in the annulus, indicating potential barrier/integrity issues pre-incident.

Table 2. Annulus Pressure Data

	BSEE Data	Taylor Report Aug 31st, 2004			BSEE Data
Well	A - annulus casing pressure (PSI)	A - annulus casing pressure (PSI)	B - annulus casing Pressure (PSI)	C - annulus casing pressure (PSI)	Well Status
A 001	1800	0	270		Producer Oil
A 002	1060	750	270		Producer Oil
A 003					Producer Oil
A 004	700		40	637	Producer Oil
A 006	440	1000	275		Producer Oil
A 007	110				Gas Lift Oil
A 008			248		Gas Shut -In
A 009		655			Gas Lift Oil
A 010	1245	1180			Gas Lift Oil
A 011	760				Producer Gas
A 012 D		37	120		Gas Lift Oil
A 013					Producer Gas
A 014		1120	200		Gas Lift Oil
A 016 D		1055			Producer Oil
A 017	2120				Producer Gas
A 018	105	250			Gas Lift Oil
A 019		1040			Gas Lift Oil
A 020		970	220		Producer Oil
A 021		775			Producer Oil
A 022		1100			Producer Oil
A 023					Producer Gas
A 024		750	50		Gas Lift Oil
A 025		875			Producer Oil
A 026		875			Producer Oil
A 028		930	350		Producer Gas

NOTE: BSEE records indicate 8 wells had active gas lift at time of incident.

- Post Incident Condition of MC 20 Wells

There exists physical and visual evidence that complete barrier / integrity loss of surface equipment occurred during the incident. As stated in the FRACE report, “At MC-20 the Christmas trees and wellheads were severely damaged and compromised as they were pulled from the deck and stripped through the jacket assembly. This was confirmed during salvage of the production deck. Essentially all the annuli and tubing above the mud-line can be considered “open-ended” in the area where the wellheads were originally installed.

Figure 22. Post Incident Condition of MC 20 Wells

- Downhole Well Barrier Components.

Production Packers:

The Baker SC-1 type production packer used on MC 20 has 15 ft. of seals and would only take 16 ft. of tubing movement upward to separate the seals from the respective SC-1 Packer bore. This loss of integrity event would break the seal barrier and expose the reservoir fluids to the A annulus and any other potential leak paths higher in the well.

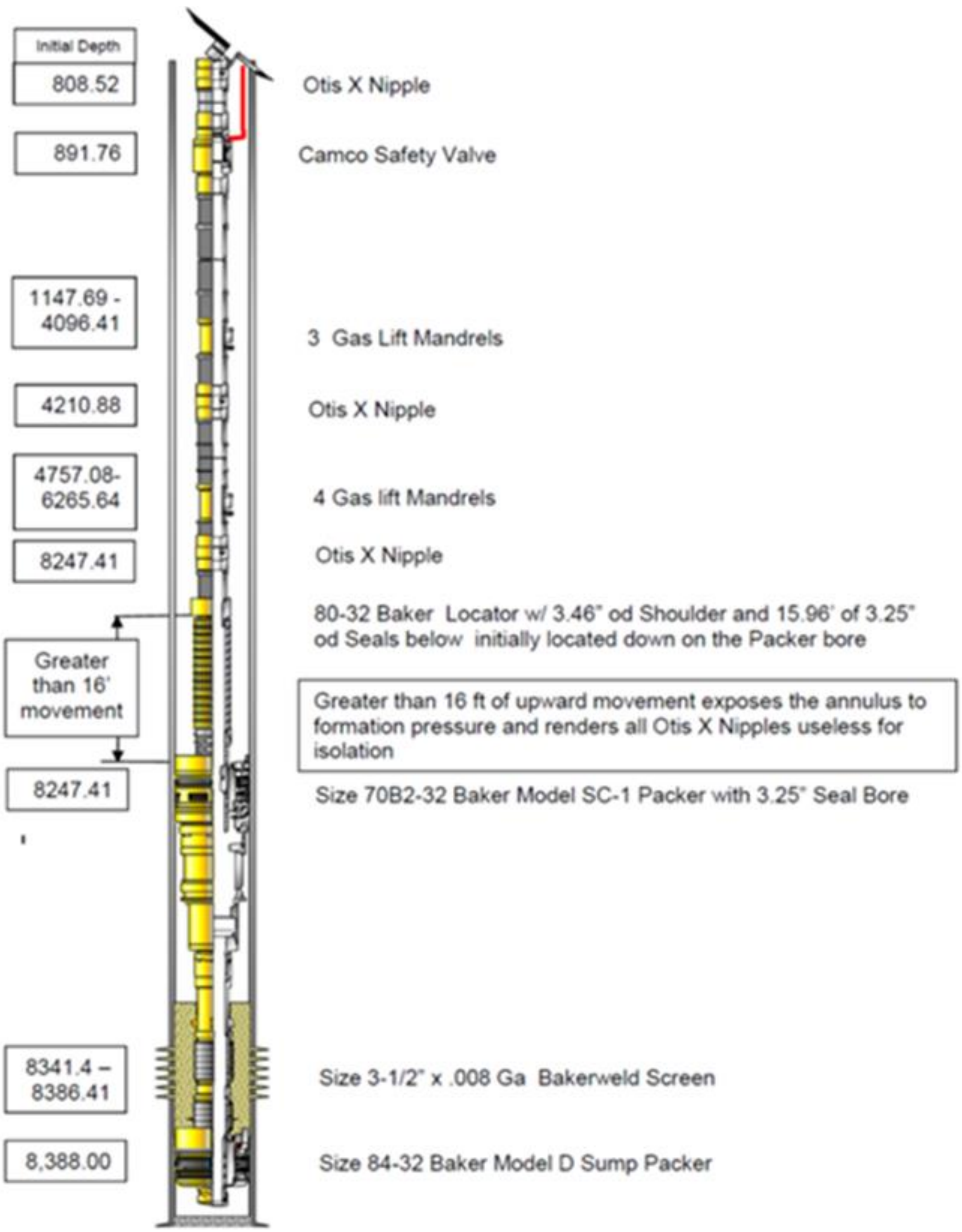

Figure 23. Packer

Baker SC-1, Schlumberger Quantum, and OSCA Comp Set Packers, which are all set in gravel pack completions, all have this same type seal/seal bore configuration and similar spacing.

Only 2 wells appear to have an extended seal bore of 20 ft. long or greater are the A-7 and A-13 wells where a Baker Model D permanent packer is set.

In the A-17, the Baker FH retrievable type production packer was set. This packer would shear out/unset at approx. 30-40k lbs. of pull from above also breaking the seal barrier and exposing the reservoir fluids to the tubing by casing annulus.

Breaching the seals/packer interface in a well completion will always result in immediate failures downhole. Once a well's tree, wellhead, valve, and/or production casing is damaged, the integrity of the well is compromised and hydrocarbons from the perforated intervals will flow in the path of least resistance.

Detailed analysis on packers and other downhole barrier components are found in the link below.

Link to Downhole Barrier Component Review

Zonal Isolation & Cement Bonding:

Zonal isolation is a critical component in well construction and also prevents hydrocarbons from leaking from one zone to another (cross flow) which can cause underground blow outs, hydrocarbon invasion into fresh water zones, and/or breaches at surface leading to safety and environmental issues.

Out of the 25 wells of interest at the time of the incident, 20 have cement bonding that is reported to be of poor, partial or unknown quality. Four wells have cement bonding that is reported as moderate to excellent.

Using the A 002 well as an example, 7 sands have potential to flow and also have partial to poor cement bonding. Reservoir fluids will flow to the path of least resistance, e.g. up alongside poorly bonded tubulars, around previous casing shoes and through other leak paths showing up at the surface or can show up as pressure in an annulus.

Table 3. A 002 Well Example Cement Bond Information

MC020: Well A-2*		Hydrocarbon	Expected	Cement	Notes
Measured Depth	Reservoir	Potential	Fluid	Bond	
9,548	L-3 RA-2	Proved	Oil	Partial	Open perfs on GL @ 9/04
9,465	L-1 RA	Proved	Oil	Partial	**Not on production**
9,265	L R20-1	Proved	Oil	Partial	**PROD from A-1 @ 9/04**
9,042	K RA	Proved	Gas	Partial	PROD from A-11 @ 9/04
8,549	J R20-1	Proved	Oil	Partial	Open (S/I) in A-3, A-8 @ 9/04
7,598		Probable	Oil	Partial	**10 feet net pay**
7,006	H RA-2	Proved	Gas	**Poor**	Open (S/I) in A-13@ 9/04
6,640		Possible	Gas	**Poor**	6 feet net pay
6,224	F R20-1	Proved	Gas	**Poor**	PROD from A-17 ST @ 9/04
5,742		Probable	Gas	**Poor**	5 feet net pay

Link to all well cement bonding review by Platt Sparks.

The wells and the associated leak paths are conduits for multiple sands to flow hydrocarbons to surface; these include targeted reservoir sands, non-targeted reservoir sands and thin interbedded sands as well as shallow sands that could potentially broach the mudline.

The graphic below depicts some of the potential leak paths outlined in the Integrity Finding on a generic well in MC 20.

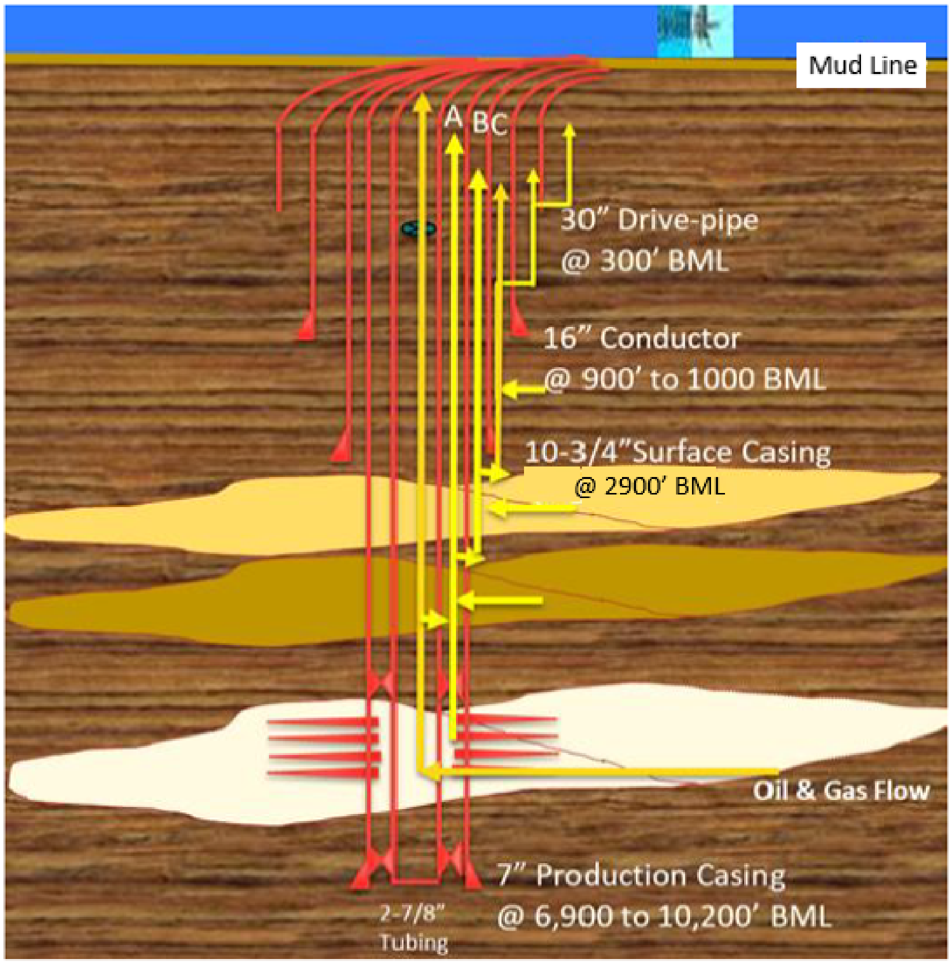

Figure 24. Potential Leak Paths On Generic Well in MC 20

The following statement in the FRACE report, support this integrity finding:

> *"At MC 20 the Christmas trees and wellheads were severely damaged and compromised as they were pulled from the deck and stripped through the jacket assembly. This was confirmed during salvage of the production deck. Essentially all the annuli and tubing above the mud-line can be considered "open-ended" in the area where the wellheads were originally installed."*

However, it should be noted, that the while the FRACE report acknowledges the failed condition of the Christmas Tree and Wellheads, **it does not appear to recognize the possibility of tubing being pulled out of the completion or other downhole integrity issues that would lead to hydrocarbons flowing up the A annulus and any other potential leak paths.**

It is essential that all potential leak paths and integrity issues are considered and addressed when designing long-term abandonment solutions.

3.4 WELL ABANDONMENT

None of the original 25 active wells prior to the incident have been abandoned per BSEE Abandonment Standard 30 CFR 250-1715. None of the applicable requirements within the standard have been met for any of the 25 wells.

30 CFR 250-1715 is the Regulatory Standard that specifies Oil & Gas Well abandonment requirements for Oil and Gas Operators. This standard represents a **Minimum** set of requirements. The illustration below represents a generic MC 20 well and associated requirements to satisfy the well abandonment standard. **None of the requirements in the standard for any of the 25 wells has yet to be achieved.**

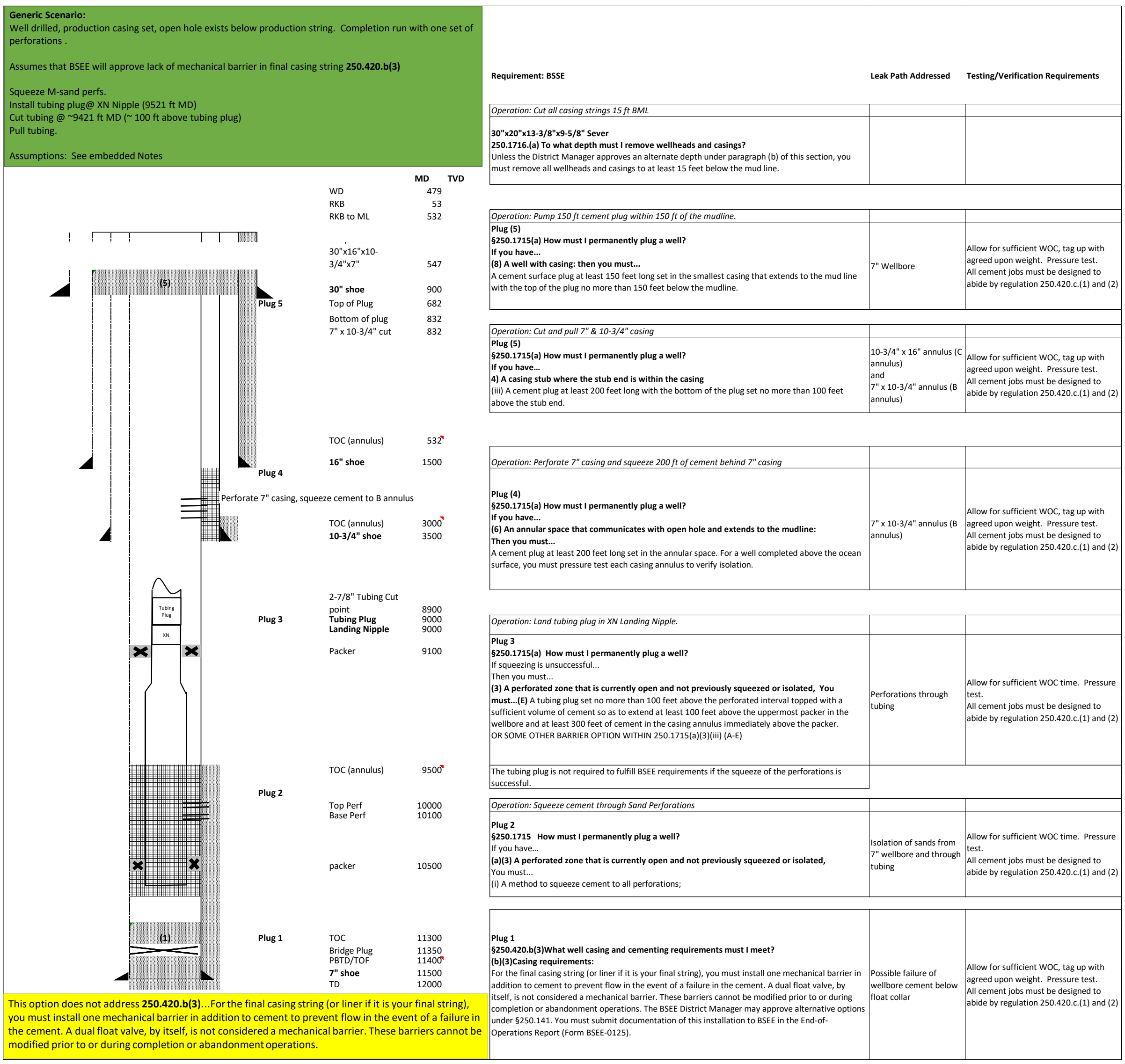

Figure 25. Generic Scenario of Operations

Well by Well Abandonment Review

- A well by well review was conducted on all 28 wells drilled at MC 20 site from the most recent "as constructed" diagrams and reports provided by BSEE. A proposed abandonment plan meeting the Abandonment Standard was created for each well.

  Link to 30 CFR 250-1715 BSEE Well Abandonment Standard
  Link to MC 20 well by well abandonment review

The 9 Intercept Wells drilled by TEC:

This section describes the difference between an intercept well that actually intersects the targeted well and the parallel well technique used by TEC and shows that none of the requirements in the abandonment standard were met for the wells targeted.

- Nine wells were drilled from 2009 to 2011 (IW Wells) in an attempt to stop hydrocarbons flowing from nine original wells that were deemed to have the highest potential to flow. Although these wells were called intercept wells, the technique used was not designed to intersect the original wells. The intent was to employ a ranging technique to drill parallel to and within close proximity to the original target well. An attempt was then made to perforate through the IW Well casing, the formation and into the target well so that cement or resin could be squeezed from the IW well into the target well.

  An intercept well (IW) that actually intersects the original well has a high probability to establish a flow path into the original well to perform well kill operations or to pump abandonment plugs; this phenomenon can be shown in the 2 cases below both from the same IW21 well:

  - Case 1) While drilling the IW 21 well TEC accidently intersected the target A21 well at 8136' approximately 400' above the targeted parallel intercept. A reported 369 barrels of drilling mud were lost (flowing into the A21 wellbore) demonstrating established communication and could have killed the well and set cement plugs.

    Rapid loss of fluid is typical of a well that intersects another well. The heavier drilling fluid in the well being drilled naturally flows to the path of least resistance, the intercepted well which has a lower column of fluid or is producing. In these cases, there is a loss of fluid, even with no additional surface pump pressure.

  - Case 2) After the accidental intercept with the A21 well, TEC continued on with the plan to parallel and perforate the A21 well. 7" casing was run and perforated below the top packer and then attempts to squeeze resin and cement were performed. Only 2 barrels of resin were squeezed with surface pressure of 1850 pounds per square inch (psi) and then 2.5 barrels of cement were squeezed with a surface pressure of 1850 psi.

    The injection fluid density, 14.4 pounds per gallon (ppg) for the resin and 16.4 ppg for the cement, along with the 1850 psi surface pressure would have broken down the formation fracture gradient of 15.2 ppg. In this case it is highly probable that the fluid would leak into the formation fracture as opposed to entering the target wellbore.

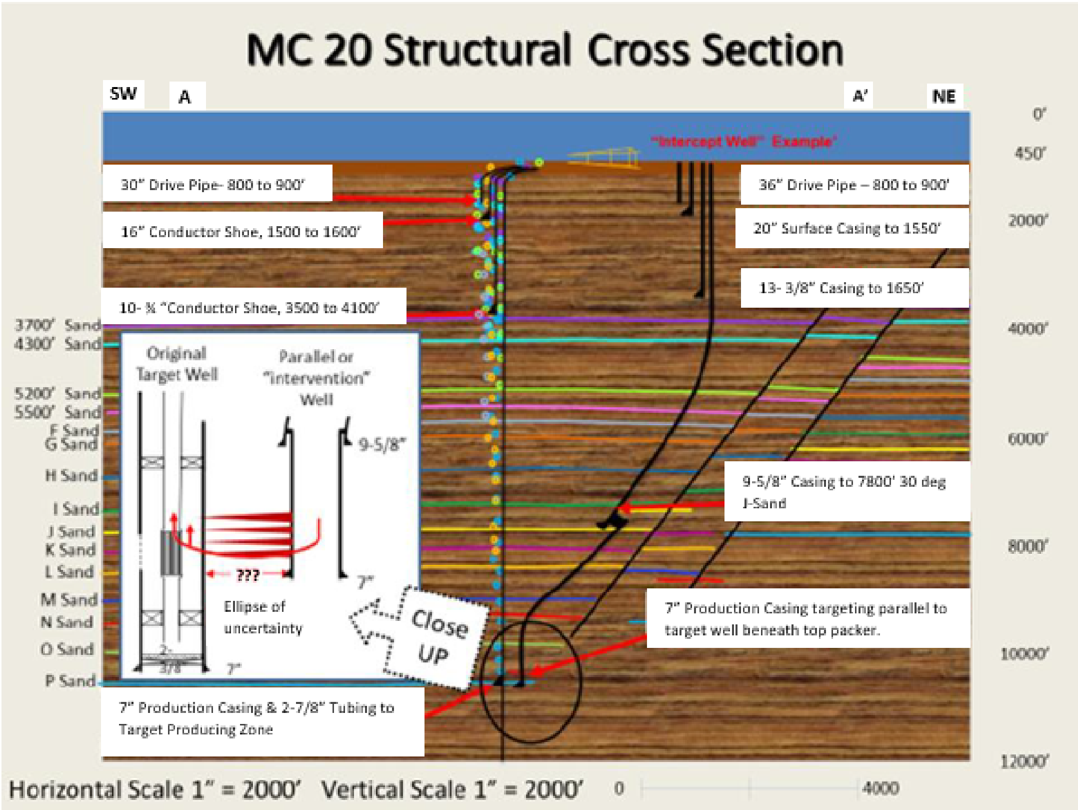

Figure 26. MC 20 Structural Cross Section

- The nine IW Wells employed a strategy to perforate below the top packer of the completion on the target wells. The following are some uncertainties associated with the technique employed:

    - Due to ellipse of uncertainty and limitations of ranging techniques, the proximity to the target well is uncertain.
    - When perforating the casing of the parallel well prior to attempting a squeeze, there exists probability of mis-fired shots; a common occurrence in perforating operations.
    - There is no guarantee how far the perforation will extend into the formation let alone or through the target wellbore casing.
    - Any fluid entering the target wellbore, must be squeezed out of the parallel well perforations, through the formation, through any cement still existing around the

wellbore and then into existing perforation of the target well. After entering into the target well, there would need to be a sufficient amount of squeeze fluid to fill the volume between packer elements as well as enter the tubing string. **Note - this scenario is flawed because it assumes the completions, packers, components and tubing have integrity (see Integrity Finding).**

  - Any squeeze fluid will follow the path of least resistance and there are many avenues that do not lead to the target well. Examples include up the side of the 7" casing where there exists questionable cement bonding, fracture or squeeze into the formation, flow past a leaking packer or through a tubing leak, or other flow paths.
  - The squeeze fluid would have to set up to sufficient strength, i.e. not get contaminated or be of substandard design.
  - If cement or resin actually squeezed into the original target and the original target well was flowing the cement would become mixed or contaminated with the flowing reservoir fluids. Contaminated cement or resin would likely not sustain its design properties and not result in an effective plug.

- Effectiveness of the squeeze attempts in the IW wells on the target wells was not tested from the target well wellbore, as would be required for verification by the abandonment standard. Any testing done from the IW well wellbore only confirms how effective the squeeze of cement or resin was in plugging the perforations or nearby formation of the IW wells themselves.

- Even given an assumption that the volume of all the cement or resin squeezed by TEC entered the target wellbore, this still does not satisfy the requirements in the abandonment standard.

- While some of the requirements in 30 CFR 250-1715 Standard address the producing zone and how to abandon that zone, the majority of the rest of the abandonment standards exist to address potential flows above the producing zone. In the case of MC 20 wells, there exists known integrity issues above the production zones as well as sands with potential to flow above the producing zones.

SUMMARY OF FINDINGS

The MC 20 field has the potential to flow from multiple reservoirs and in fact is flowing oil, gas and water from the subsurface source to the surface from multiple wells. All wells are conduits from the subsurface source (multiple reservoirs and sands) to the surface and have multiple potential leak paths in the wells (integrity and barrier issues). None of the original wells have met any of the regulations in the permanent abandonment standard, including the nine wells targeted by the TEC intervention attempt. Oil, Gas and Reservoir water will continue to flow from the subsurface source through and/or around the conduits (the wells) into the Gulf and the situation will get worse over time due to continued deterioration of tubulars and well barriers, as well as recharging of the reservoirs due to the existing aquifer drive support mechanism. The RSS containment system is only a temporary containment system. It is critical to implement a source control and/or permanent abandonment recommendation.

4.0 OPTIONS TO ACHIEVE PLUGGING AND ABANDONMENT STANDARDS

This section gives an overview of the options identified to secure the source and/or achieve Plugging and Abandonment standards. It documents work done to close gaps in Task 8, a critical technology trial to image the conductors and tubulars under the mudline, risks associated with the options, and the results of an option ranking process and workshop. All options were risk assessed by the Project Team and Firms with Industry Specific Technical Experience (FISTE) to assure that the activity can be conducted in a manner that is safe, does not interfere with other uses of the Outer Continental Shelf (OCS), and does not cause undue or serious harm or damage to the human, marine, or coastal environment (30 CFR 250.1703(g)). Option specific approaches and details are found in the **Option Specific Approach & Details** (see subsection 4.4) of this section. Note the work done on these options is for proof of concept not for construction.

4.1 CONTEXT

Prior to embarking on Task 8 and Task 9, the recommendation from FRACE to address the MC 20 spill was to do nothing based on erroneous conclusions that very little if any Oil & Gas was coming from the source, that nothing could be done and that if anything were attempted it would make the situation worse.

Due to the successful installation of the Rapid Response System in Tasks 1 through 7 oil is now being contained, captured, stored and offloaded reducing the Oil & Gas effects on the environment. Additionally, the work done in Task 8, has identified new options to achieve isolation from the subsurface source in the wells and even to potentially abandon all the wells per the BSEE CFR 250.1715 well abandonment standard.

High Level Summary of Options identified and reviewed:

1. Excavation to Access the Wells and Intervention

   This option involves first excavating some of the mud that buried the site exposing the well conductors & tubulars ends. The second phase in this option re-establishes a secure connection to the exposed well tubulars. Once a secure connection is established the wells will then be entered to secure the source and or achieve the abandonment standard.

2. Intersecting Intercept Wells

   As noted in Section 3.4 of this report, Taylor Energy drilled 9 parallel intercept wells which were unsuccessful in achieving source control. This option uses a different intercept well strategy, to actually intersect the target wells to establish a direct communication path for setting source isolation and/or abandonment plugs vs. TEC unsuccessful technique of drilling parallel the target wells and attempting to squeeze fluid across the formation.

3. Depletion

   The depletion option is basically status quo situation of carrying on with the capture, containment and offloading until the field is completely depleted, which is estimated to be between 50 and 100 years. It is recognized that the current system Rapid Response System was not designed for this period of time and it is expected that new plumes will occur, as such a concept for a mobile containment system has been developed for this option.

4. Accelerated Depletion

   In accelerated depletion, new wells would be drilled, completed and a producing facility or subsea infrastructure would be put into place to offtake the oil and gas accelerating the production to deplete the field at a faster pace.

The above descriptions are high level summary of the options, a more detailed description to include conceptual engineering designs and reviews with Firms with Industry Specific Technical Expertise (FISTE) are documented and found later in this section.

Link to Option Specific Approach & Details

Each of these options has its own challenges, risks and benefits. All the options have been reviewed via a rigorous and systematic process taking risks, feasibility, costs, schedule, environmental concerns and source control / abandonment goals into account. The process and results are documented in section 4.2.

4.2 MC 20 Task 8 & 9 Risk and Option Ranking Exercise

The Risk and Option Ranking exercise as part of MC 20 Task 9 provides a framework to inform recommendations and decision-making moving forward to achieve sub-surface source control and/or achieving plugging and abandonment standards. This process was geared at identifying safe and viable options to address the MC 20 spill. It was not meant to eliminate any options.

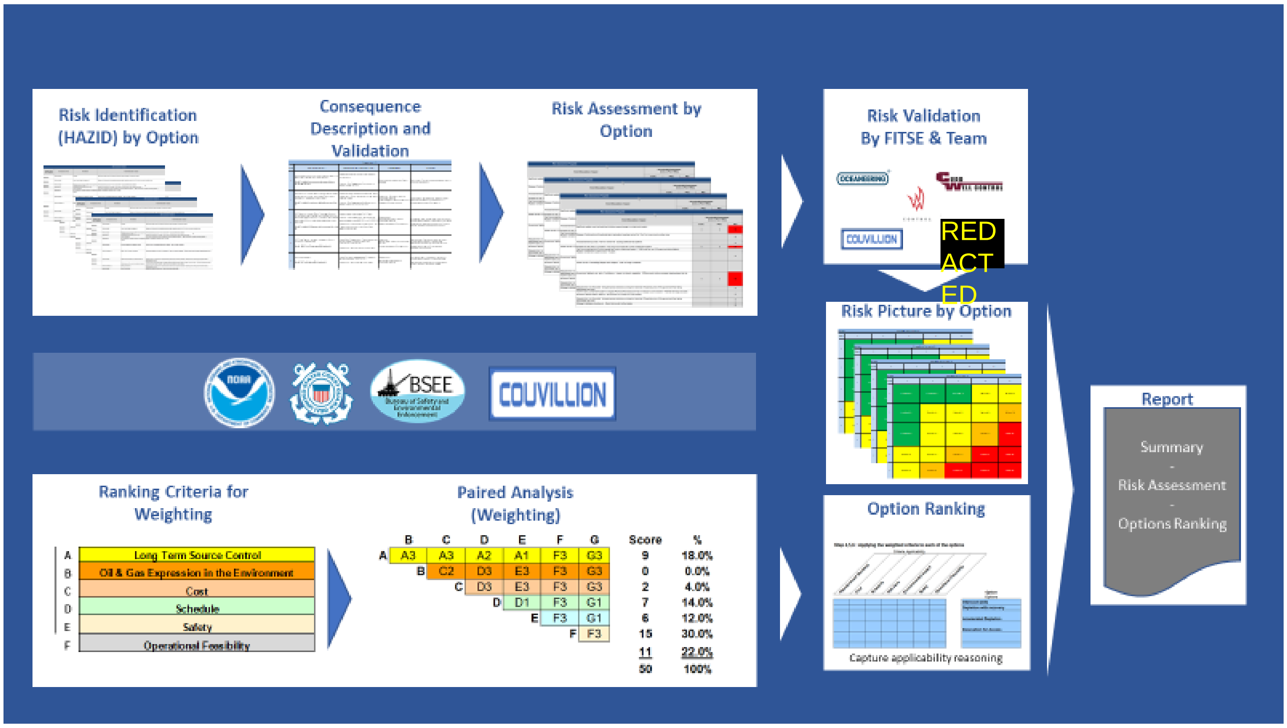

Figure 27. MC 20 Risk and Option Ranking Process

[Link to MC 20 Risk and Option Ranking Process and Results]()

The following Options / Operations were evaluated (Operation and associated FISTE):

1) Excavation to Access the Wells and Intervention
   - Excavation to access the wells – REDACTED & Geotechnical Expert
   - Reconnect to the wells – Oceaneering
   - Intervention Wells (Wireline) – Oceaneering
   - Intervention Wells (Coiled Tubing) – Cudd Energy Services
2) Intercept Wells – Wild Well Control & Cudd Energy Services
3) Depletion - Couvillion Group
4) Accelerated Depletion – Couvillion Group

Stakeholders involved in the process:

- Decision-Making Body: USCG, BSEE & NOAA
- Project Team: Couvillion Group and the Decision-Making Body
- FISTE: REDAC Engineering & Geotechnical Expert, Wild Well Control, Cudd Energy Services, Oceaneering

4.3 Results of the MC 20 Task 8 & 9 Risk and Option Ranking Exercise

1. Risk Assessment:

Each option has undergone HAZID, Risk Evaluation / Assessment, Ranking, Mitigations Identification and Reassessment of Risk Rankings. This process involved the project team and FISTE and was validated by all participants.

During the process hazards / risks were generated and categorized into the following groups:

- Health & Safety
- Operations (Cost & Schedule)
- Environmental
- Public Confidence

Each risk was assigned a value for consequence severity and also for probability.

RISK ASSESSMENT MATRIX (RAM)					
Rank	1	2	3	4	5
1	Acceptable (1)	Acceptable (2)	Acceptable (3)	Moderate (4)	Moderate (5)
2	Acceptable (2)	Moderate (4)	Moderate (6)	Moderate (8)	Serious (10)
3	Acceptable (3)	Moderate (6)	Moderate (9)	Serious (12)	Critical (15)
4	Moderate (4)	Moderate (8)	Serious (12)	Critical (16)	Critical (20)
5	Moderate (5)	Serious (10)	Critical (15)	Critical (20)	Critical (25)

Figure 28. Generic Risk Matrix

Mitigations were then identified for the risk, which were then re-assessed for potential reduced consequence and/or probability. The results were validated and agreed upon by all the participants.

The risk assessment process and tool are intended to be kept live throughout the project to highlight and reduce risks. Risks will continue to be assessed and reviewed, mitigations developed and risked reassessed as plans develop, prior to operations beginning and during operations; this is a key aspect of the risk ranking and assessment process. The next phase of Front-End Engineering Design (FEED) will pick-up the risk assessment tool and continue where this phase left off.

2. Option Ranking:

Background:

Understanding priority is an important part of making good decisions. An increasing number of priorities / criteria will raise the level of complexity associated with a decision. Introducing more stakeholders to the decision will further multiply the complexity and possibly to a point where a decision through consensus is difficult to achieve. Pairwise Analysis is a methodology that is applied as a way of deconstructing complexity into smaller components and pairs where subjective and objective data can more easily be prioritized, and biases minimized.

Criteria Identification:

The process requires the following:

1. Clearly capture a description of the criteria by the Project Team
2. Fully agree to the criteria and description by the Decision-Making body
3. Criteria (but not weighting) can be shared with FISTE as part of Risk Assessment and Option Ranking
4. While criteria can be shared with FISTE, the pairwise analysis of criteria and discussions by the Decision-Making Body are confidential and should not be shared at any time with FISTE.

Criteria used by the project team to evaluate the options:

- Long-term Source Control
- Oil & Gas Expression in the Environment
- Costs
- Schedule
- Safety
- Operational Feasibility

To aid in defining the criteria and assist in the weighting process, applicability parameters were developed, agreed and recorded. Further descriptions, definitions and details of the process and results are found in the document Risk and Option Ranking Process and Results document which is referenced and linked above.

Weighting of the criteria

Pairwise Analysis was applied in order to get the weightings for the criteria. Following the exercise to determine priorities, an output containing the weighting of the criteria was recorded and used in the ranking session.

Step 4,5,6 : Applying the weighted criteria to each of the options

Criteria Applicability: Long Term Source Control	Oil & Gas Expression in the Environment	Cost	Schedule	Safety	Operational Feasibility	#	Option	Criteria Weighting x Applicability: Long Term Source Control	Oil & Gas Expression in the Environment	Cost	Schedule	Safety	Operational Feasibility	Value	Ranking
								0.26	0.13	0.03	0.00	0.32	0.26		
2	2	2	1	2	2	1	Intercept wells - WWC	0.52	0.26	0.06	0.00	0.65	0.52	2.00	
2	2	2	1	2	2		Intercept wells - Cudd	0.52	0.26	0.06	0.00	0.65	0.52	2.00	
1	2	1	1	1	2	2	Depletion with recovery - Couvillion	0.26	0.26	0.03	0.00	0.32	0.52	1.39	
2	1	1	1	1	1	3	Accelerated Depletion - TBD	0.52	0.13	0.03	0.00	0.32	0.26	1.26	
						4	Excavation for Access - Excavation - RED								
							Oceaneering								
							Excavation for Access - Wireline - Oceaneering								
3	2	3	2	2	2		Excavation for Access - Aggregate w/Wireline	0.77	0.26	0.10	0.00	0.65	0.52	2.29	
						4	Excavation for Access - Excavation REDA								
							Oceaneering								
							Excavation for Access - Coiled Tubing - Cudd								
3	2	3	2	2	2		Excavation for Access - Aggregate w/Coil tubing	0.77	0.26	0.10	0.00	0.65	0.52	2.29	

Figure 29. High-Level Summary of Option Rankings

Graphic Shows a High-Level Summary of Option Rankings, detailed explanation, defining parameters and weighting of the criteria can be found in the Risk and Option Ranking Process and Results document which is referenced and linked above.:

3. Summary of Results by Option:

In the evaluation of each of the options a common mitigating action is having a mobile containment system ready for deployment at the dock was identified. Details on this system are provided both in the detailed section of the Risk and Option Ranking Process and the Summary Section for the Depletion Option. This system would need to be built and capable of being deployed before the next stage of offshore construction work were to begin.

1) Excavation to Access the Wells and Intervention (wireline and/or coiled tubing)

This option received the most favorable score of 2.29 (out of a maximum possible of 3.0) and risks were assessed to be at an acceptable level. It is viewed as having the greatest chance at achieving the long-term source control criteria and is the only option that could potentially achieve the abandonment standard. It is also the option with the least cost & schedule and viewed as the safest option. With respect to safety, industry data shows that diver safety while similar with drilling operations is actually slightly more favorable than drilling operations.

Table 4. Option 1 Excavation to Access the Wells and Intervention

Risk	**Pre-mitigation**	**Post-mitigation**
	Critical – 8	Critical – 0
	Serious – 9	Serious – 0
	Moderate – 11	Moderate – 14
	Acceptable – 0	Acceptable – 14
Options Score:	**2.29**	
Cost:	**$208-214MM**	
Schedule	**3.4 Years**	

2) Intersecting Intercept Wells

This option received the 2nd most favorable score of 2.0 and risks were assessed to be at an acceptable level. It should be noted that two FISTE (Wild Well Control and Cudd Energy Services) presented similar approaches, were evaluated independently and both received the same score. This option did not score as high in the long-term source control criteria due to the inability to set abandonment plugs above the upper sands with potential to flow. It is also estimated to be more costly and take longer, however these criteria were weighted less than both the long-term source control and the feasibility criteria.

Both option 1 and option 2 scored the same on the feasibility and Oil & Gas Expression in the Environment criteria.

Table 5. Option 2 Intersecting Intercept Wells

Risk	**Pre-mitigation**	**Post-mitigation**
	Critical – 13	Critical – 0
	Serious – 7	Serious – 2
	Moderate – 10	Moderate – 16
	Acceptable – 2	Acceptable – 14
Options Score:	**2.00**	
Cost:	**$425MM-$658MM**	
Schedule	**5+ years**	

3) Depletion

The depletion option received a less favorable score of 1.39. The option received the lowest possible scores (1) in the following criteria; Long-term source control, Cost, Schedule & Safety (4 of the 6 categories). It was not viewed as safe or viable as risks for this option in each category (Safety, Environmental, Operational & Public Confidence) are found to be outside the acceptable risk tolerance level. This includes risk levels at both pre-mitigation and post-mitigation. The main driver for risk in this instance was the longevity of the option, 50 to 100 years, as this time frame drives up both the probability and consequence values which increases the overall risk severity.

However as described in the risk section and in the overall analysis below, this option in combination with other options and used for a limited time frame is viewed favorably and viable along with using options 1 and/or 2 simultaneously to achieve source control and/or the abandonment standard.

Table 6. Option 3 Depletion

Risk	**Pre-mitigation**	**Post-mitigation**
	Critical – 9	Critical – 9
	Serious – 2	Serious – 0
	Moderate – 2	Moderate – 4
	Acceptable – 1	Acceptable – 1
Options Score:	**1.39**	
Cost:	**$425MM-$658MM**	
Schedule	**50-100 years**	

4) Accelerated Depletion

Accelerated depletion option scored the lowest score of 1.26 and received the lowest possible score in 5 of the 6 categories. It received a score of 2 in the long-term source control category as all wells would still need to be abandoned in this option. It was not viewed as safe or viable as risks for this option in every risk category (Safety, Environmental, Operational & Public Confidence) are found to be outside the acceptable risk tolerance level. This includes risk levels at both pre-mitigation and post-mitigation. This option retained the highest risks of any option reviewed.

Table 7. Option 4 Accelerated Depletion

Risk	**Pre-mitigation**	**Post-mitigation**
	Critical – 31	Critical –13
	Serious – 13	Serious – 2
	Moderate – 19	Moderate – 28
	Acceptable – 1	Acceptable – 21
Options Score:	**1.26**	
Cost:	**>$1BN**	
Schedule	**>25 years**	

Details of the Risk Ranking and Assessment Process and Detailed Risks Assessment for each option can be found in the link to the detailed report.

4. <u>Overall analysis and recommendation:</u>

As stated in the summary of this section, this process was targeted to identifying safe and viable options to address the MC 20 spill and to rank the options informing the Decision Making-Body with a way forward. The options are not viewed as a one size fits all and it is recognized that a combination of safe and viable options will be needed to best achieve the weighting criteria and the overall objective of securing the source and/or abandoning the wells.

Based on the Risk and Option review it is recommended to begin with Option 1 (Excavation to Access the Wells and Intervention) to assess the wells and attempt to achieve abandonment or source control. If it is determined that only a top plug can be set or access cannot be achieved, then Option 2 (Intersecting Intercept Wells) would be employed. All the while, containment and offloading of the oil would continue with Option 3 – Depletion, until source control is achieved. This progression also has the advantage of being able to detect which wells are actually leaking prior to simply drilling costly intercept wells. Additional advantages in using this progression include it being the lowest cost option with the most optimum schedule and least risk.

As of note, both intercept well FISTE (Cudd Energy Services and Wild Well Control) also recommended the approach above.

While the recommended options for the way forward are deemed to be safe and viable, it is recognized that more detailed engineering must be done for further development and refinement. Front End Engineering Design (FEED) is recommended for Options 1 & 2 along with the Mobile Containment System to mitigate any additional plumes or failure to the current Rapid Response Containment System.

Details of the Option Ranking and Assessment Process for each option can be found in the Risk and Option Ranking Process and Results document which is referenced and linked above.

4.4 OPTION SPECIFIC APPROACH & DETAILS

4.4.1 BACKGROUND & CONTEXT:

There were 25 active wells and 3 wells which were temporarily abandoned at the time of the incident. The below illustration is a depiction of the wells and jacket post incident.

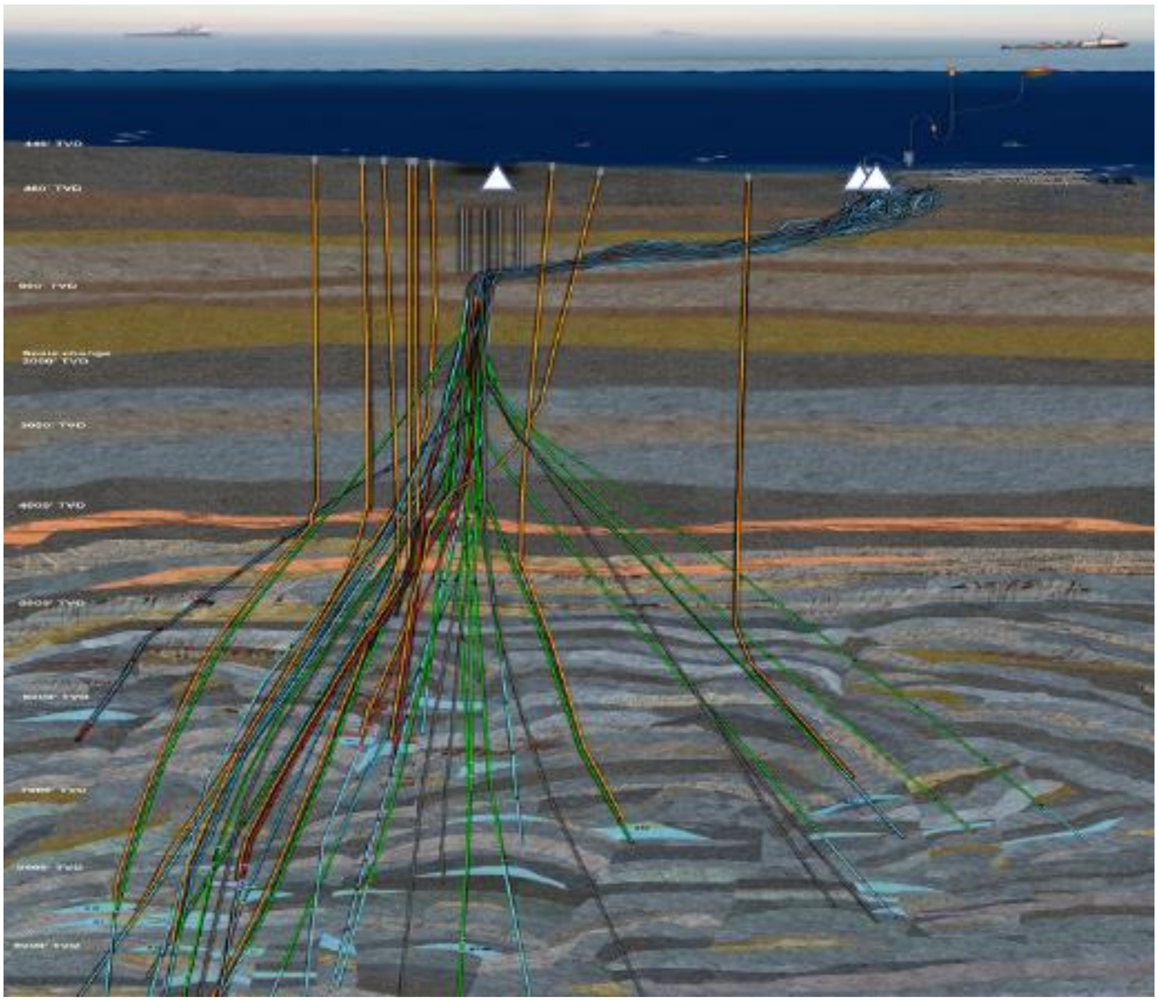

Figure 30. Depiction of Wells and Jacket Post Incident, the yellow lines represent TEC's parallel intercept wells which were unsuccessful in stemming the flow of oil to the environment.

While it is known that some of the valves were stripped off the tubing spools exposing the annuli and trees were also broken off, a complete recording and documentation of the damage has not been identified in the Task 8 data review.

A certain level of understanding of well conditions and configurations is critical to developing a plan to re-enter the wells. While there is a lot of speculation, it is not known exactly what happened to the well conductors, casings and tubulars; several leading theories include:

- The tubulars were pulled by the jacket and bell guides bending at 90 degrees at the old mudline, this theory does not easily explain the plumes emitting at the current jacket location as the 90-degree bend and length of the tubulars would have the tubular ends well short of the plume locations.

- The tubulars were pulled by the jacket and bell guides, but did not bend at 90 degrees. The soft Gulf of Mexico top sediment gave way allowing for the conductors and tubulars to start bending deeper creating a softer radius of curvature. This theory would explain the oil plumes emitting at the current jacket location almost 550' away from the well bay area and also lend support to having more accessible tubulars.

- Post-incident reports state that the valves were ripped off the trees, exposing the annuli and it is suspected that some or all of the tubing hangers failed at the connections of the casings. All casing strings are cemented creating a foundation, which would most probably cause failure of the bolts and flanges attaching the tubing head spools. The only non-cemented tubular is the 2-7/8" or 2-3/8" production tubing that employed a rubber seal element at the packer (see finding 3.3). The production tubing could have pulled out of the packer and stripped out of the inner casings dragging with the tubing head spools to a final resting place.

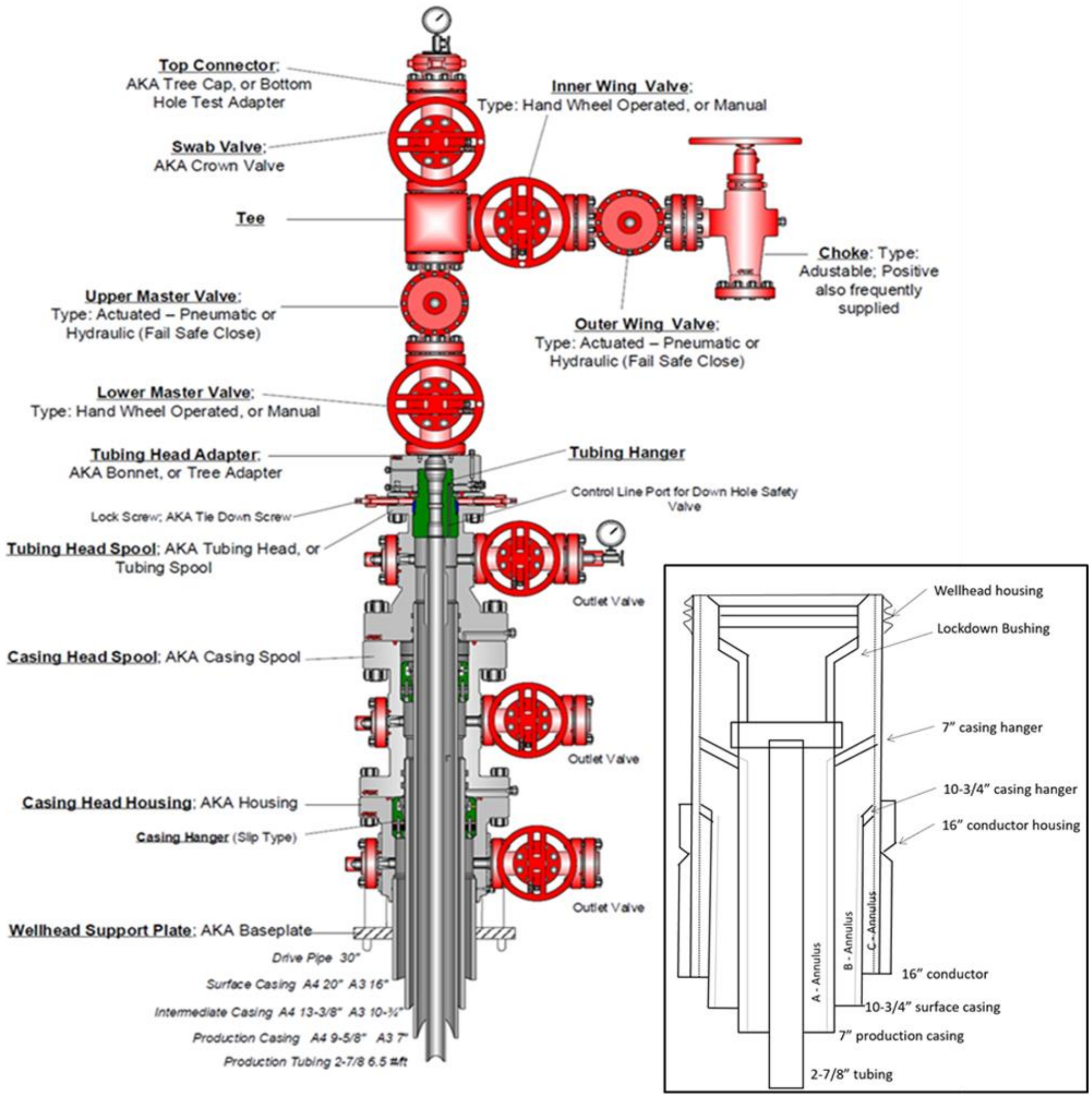

Figure 31. Typical Wellhead and Tree Schematic. Any connection or valves that were ripped off or damaged would cause a leak path.

In summary, it is not known if the tubulars are stripped out of the tubing spools, broken off, twisted or a combination of these effects, additionally the configuration of the tubulars and radius of curvatures are not known.

The MC 20 platform wells typically employed a 30” drive pipe followed by 16” casing, then 10-3/4” casing and then 7” (or 7-5/8”) production casing with 2-3/8” (or 2-7/8”) production tubing configuration (see example casing schematic below).

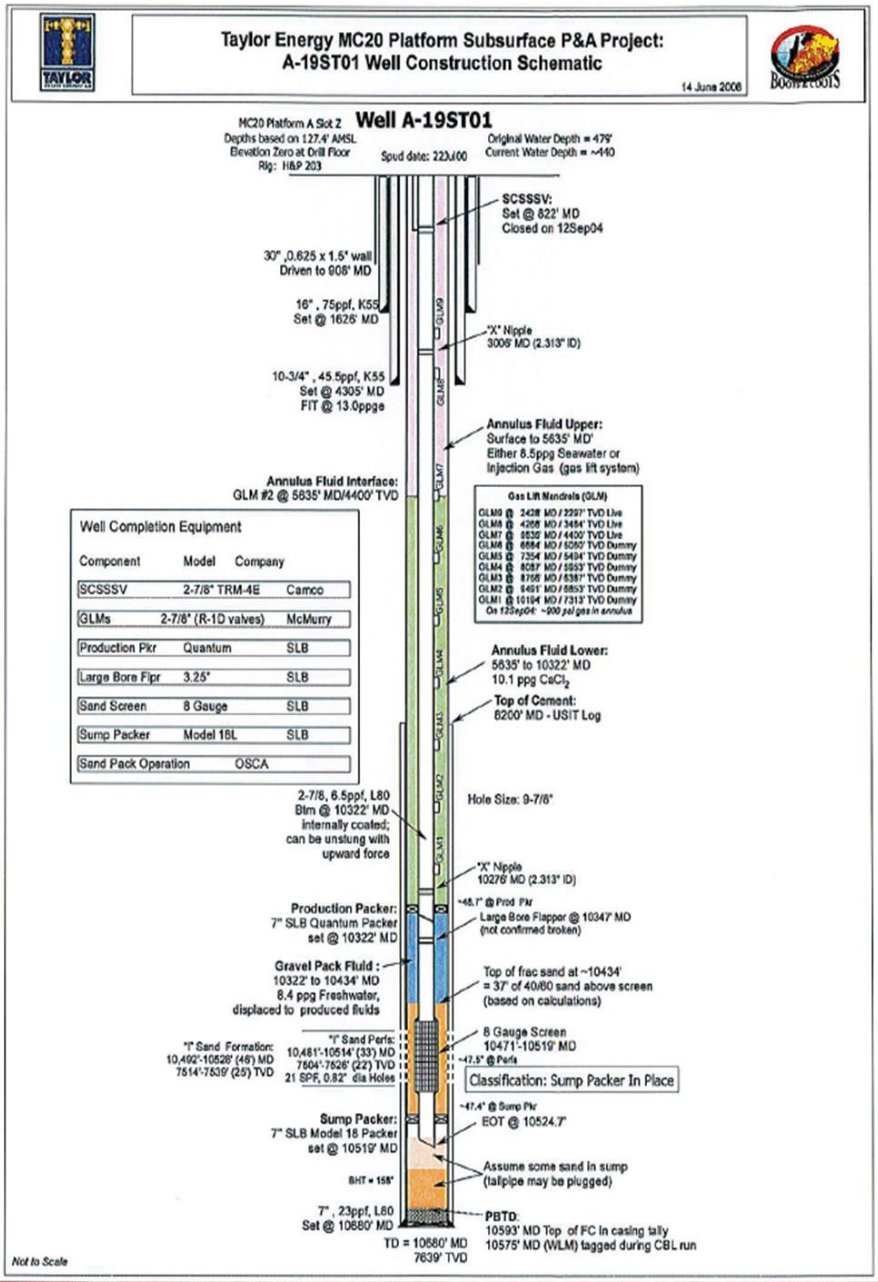

Figure 32. A-19ST01 Well Construction Schematic

In the post incident analysis Taylor Energy commissioned a test to bend the tubular configuration at 90 degrees in a controlled environment and then cut to see a cross section of the inner tubulars, the results are shown in the below photos. **As stated above the actual bend angles and radiuses are not known**. It should be noted in this sever case that the inner 2-7/8” tubular while incurring ovality, still remains a viable path for access or cement plugs to be pumped down.

Figure 33. TEC Controlled 90 Degree Bend Test of Tubular

Significant uncertainty remains in the downhole condition of the MC 20 wells and conductor bundles buried beneath sediments from a mudslide or slump in September 2004. The stripping of the large steel jacket from 28 well conductors and the shearing of multiple surface well valves are indicative of the tremendous forces on the MC20 wells and conductors. All of the aforementioned uncertainties, to include depths of conductors, tubulars and debris below the existing mudline hinder the approach to accessing the conductors and tubulars. While reviewing the site data in Task 8, the ability to locate the conductors and tubulars was identified as a key data gap to either establish source isolation plugs or achieve full abandonment to the standard.

4.4.2 Technology Trial to Image and Locate the Well Conductor / Tubulars Below the Mudline

During Task 8, a review of technologies through market research revealed that acoustic technology had been advanced in the wind farm energy sector which would give high probability of being able to image the conductors with the desired resolution and parameters.

The sub-surface conductor imaging survey was conducted in September 2019. The Acoustic Corer 3D sub-bottom imaging technology uses multi-aspect acoustic imaging to delineate sub-seabed stratigraphy and buried geohazards such as boulders, hard layers, shallow gas, and abandoned seabed infrastructure.

The unit consists of two sonar heads attached to each arm of a 12m (40 ft) boom. A tight grid of acoustic data is acquired as the boom rotates 180° thereby creating a 360° acoustic core.

Figure 34. Acoustic Corer (on Tri-Pod)

As the location, depth of burial and configuration of the conductors and associated tubulars are unknown, the technology and ability to accurately image the conductor and associated tubulars was deemed critical in both excavation planning and being able to access the well to perform abandonment operations.

The Interagency Work Group approved a trial of this technology to survey and image the conductors and tubulars sub-surface, which would help to understand depth of burial, configuration, potential radius of bend and any stripping of internal tubulars. In part, the information would be used to formulate a plan to excavate and gain access to the conductor ends.

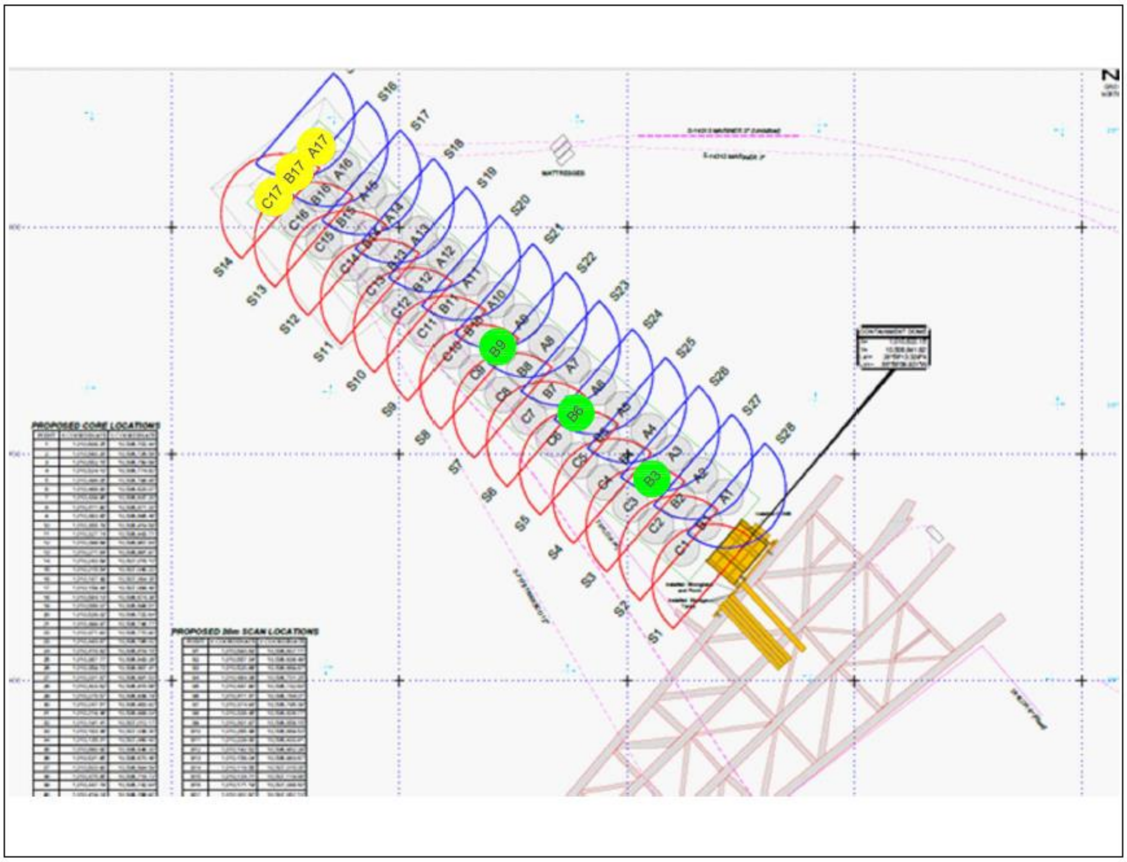

Figure 35. Depiction of Full Field Scan Scenario, B3, B6 & B9 locations were chosen for the technology trial.   The original well bay area is along row 17.

Prior to execution a test run was made REDACTED [redacted] Three scans were taken at locations B3, B6 and B9. Soil disturbance data was also captured REDACTED [redacted]

REDACTED [redacted]

Three scans were performed and proved the technology, providing 40 ft diameter cylindrical images to a depth of more than 130 ft below the mud line.

The results showed multiple man-made linear features in each scan location.

- B3 – 4 linear features
- B6 – 2 Linear features
- B9 – 6 Linear features

The linear features in these locations were imaged between 30 ft to 70 ft below the mud line with diameters of 8" ± 1" up to 30" ± 3".   Other debris were imaged and located up to 90' below mud line.

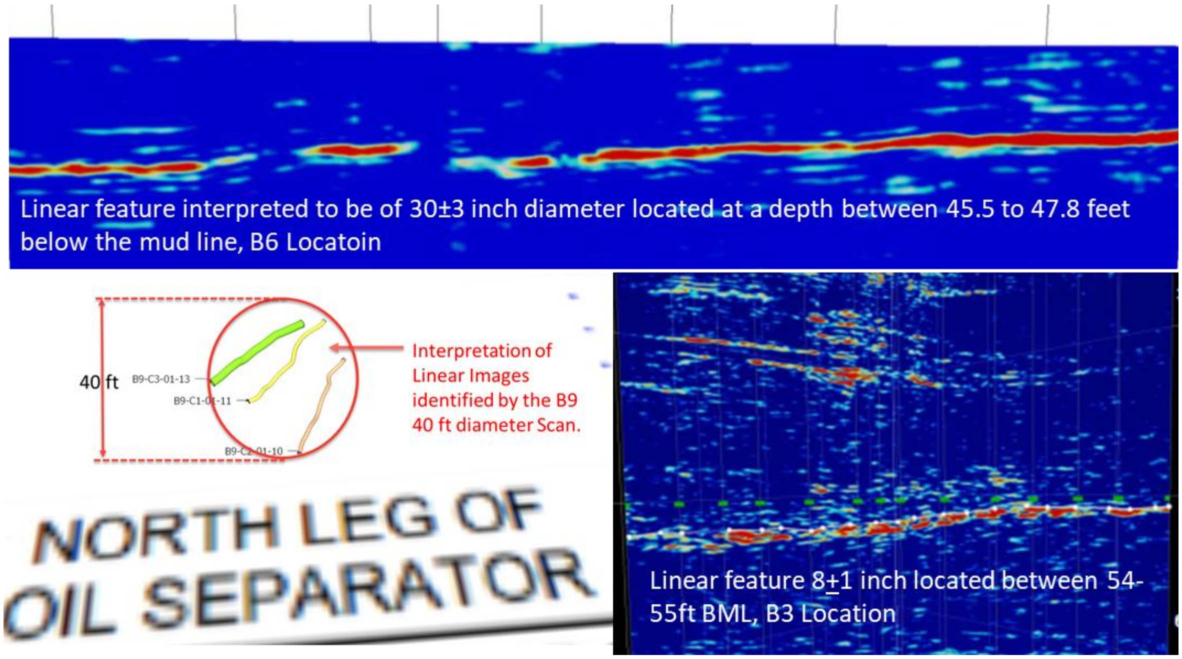

Figure 36. Scans output and interpreted Linear Features

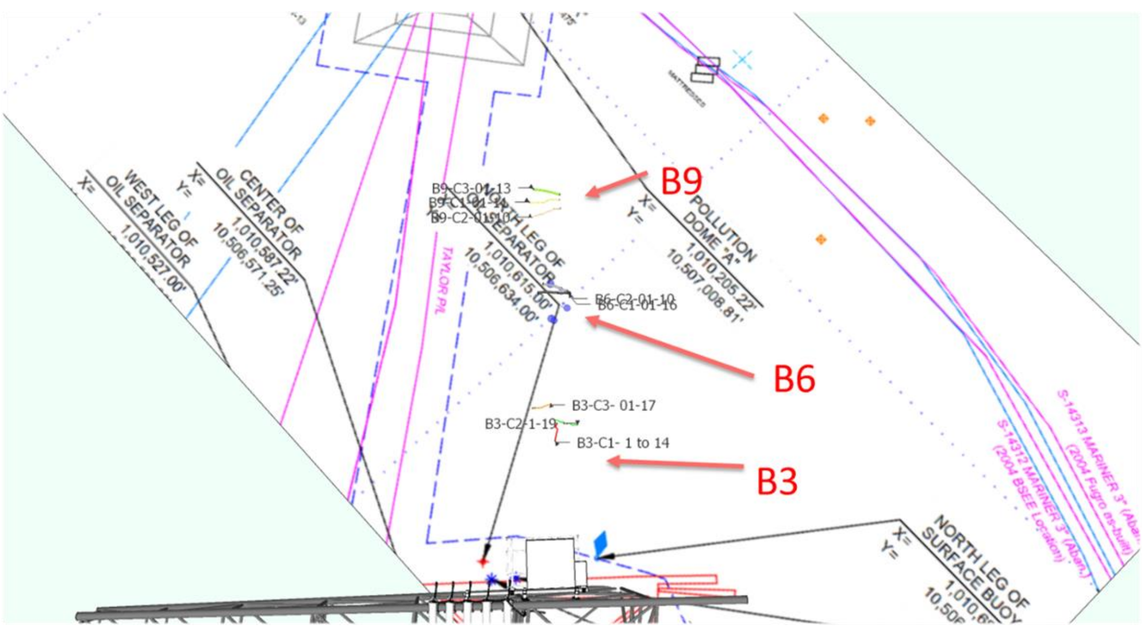

Figure 37. View of B3, B6 and B9 Scan Locations in relation to the site.

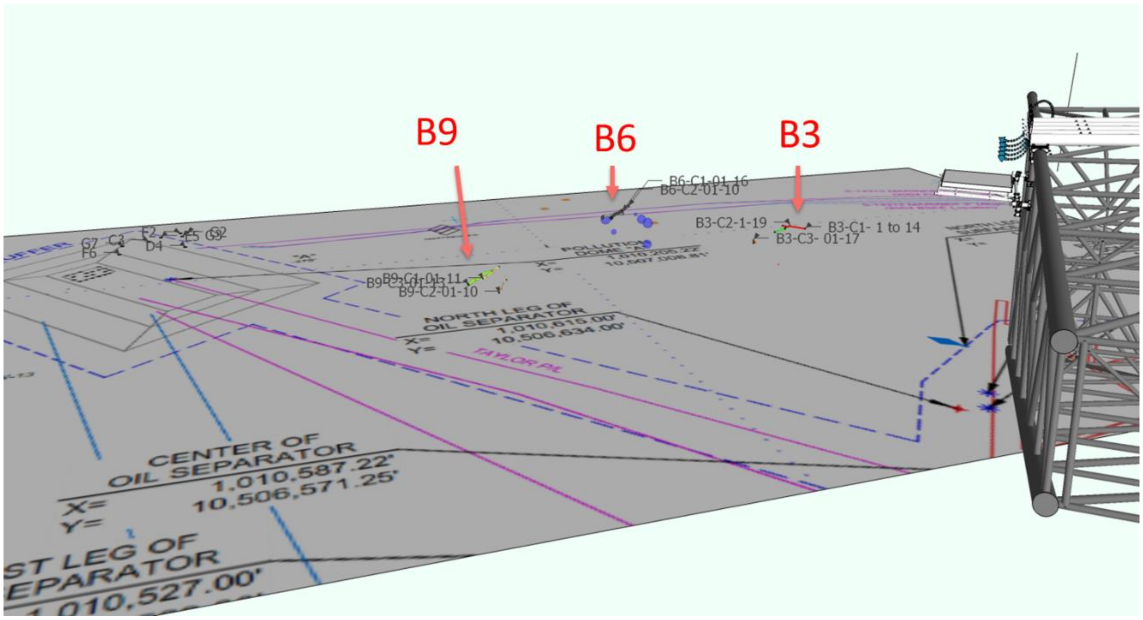

Figure 38. Another View of B3, B6 and B9 scan Locations in relation to the site.

[Link to Pangeo AC Corer Sub Bottom Imaging Report]

The results of the three PanGeo Acoustic Corer scans gathered during the technology trial along with soils strength data have been used to develop conceptual excavation engineering design and plans.

However, even with the technology proven, this survey work provided just a small sample. It does not yet provide a complete enough picture to resolve the depth, location and configuration of the conductors and tubulars required to reduce the uncertainties in the excavation and intervention options. Expanded field wide scans are needed to gain the level of detail and needed information to develop refined & robust excavation, reconnection to wells and intervention plans.

4.4.3 Options to Achieve Source Control and/or Abandonment

1. <u>Excavation to Access the Wells and Intervention</u>

This option requires to first excavate to expose and gain access to the conductors (or tubulars). Next, to re-establish an integral connection to the wellbore tubulars. Followed by entering the wells to perform intervention operations to either establish isolation plugs for source control or to achieve the full abandonment standard.

- Excavation to gain access to the conductors

  With the results of the 3 PanGeo field trial scans and soils structural analysis in hand, excavation moved beyond the conceptual phase. As of the date of this report, two viable engineered excavation options to expose the conductors and tubulars have been identified for future wellhead re-connection and intervention work. Plans will continue to be refined based on future field-wide Acoustic Corer scans.

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

REDACTED

[redacted]

Excavation of the Mud

A 70 ft wide x 320 ft long x 65 ft hole would require about 54,000 cu yds of dredging. The 30 ft deep pit with 6 to 1 slope would require an additional 750,000 cu yds of excavation. While this project may appear large, it is actually small when compared to yearly dredging volumes commonly conducted, as an example in Louisiana alone the US Army Corp dredges over 100 million cu yds every year.

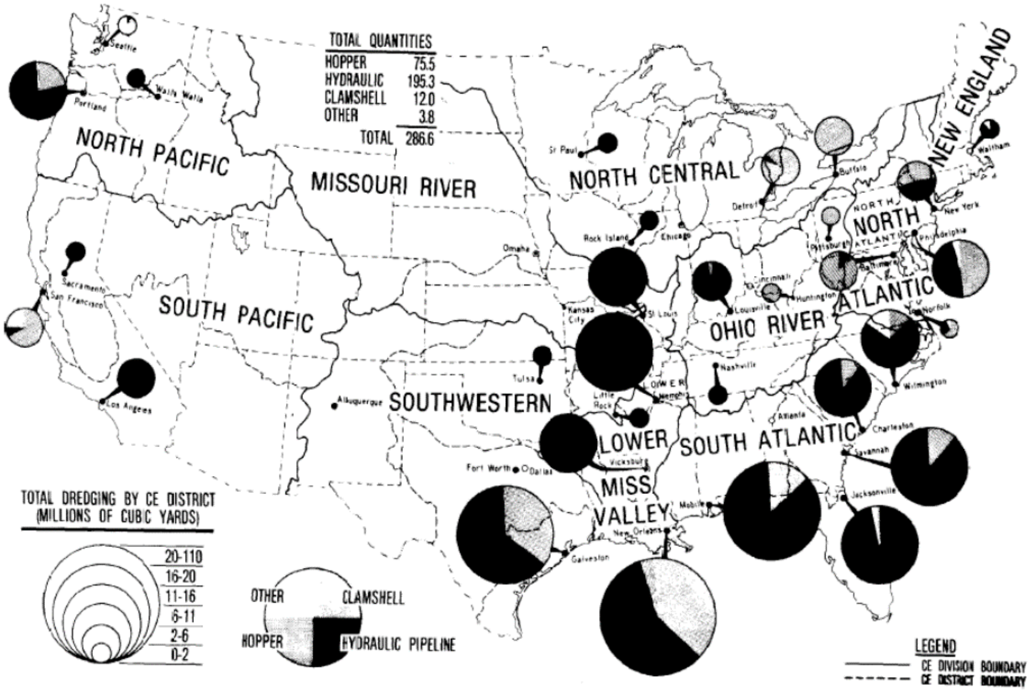

Figure 45. Yearly Dredging Volumes in the United States

Several dredging vessels and tools have been identified to perform the required excavation, some of the tools for the excavation operation are shown below:

Figure 46. Dredging Vessels and Tools

Figure 43 left picture shows Cornell Pumps 8NHG19 130 cu yards per hour highly portable and adaptive to depth. Figure 43 right picture shows Robotic Cutter head dredge.

Figure 47. Eddy Pump 12" Cutter Head Dredge (Robotic)

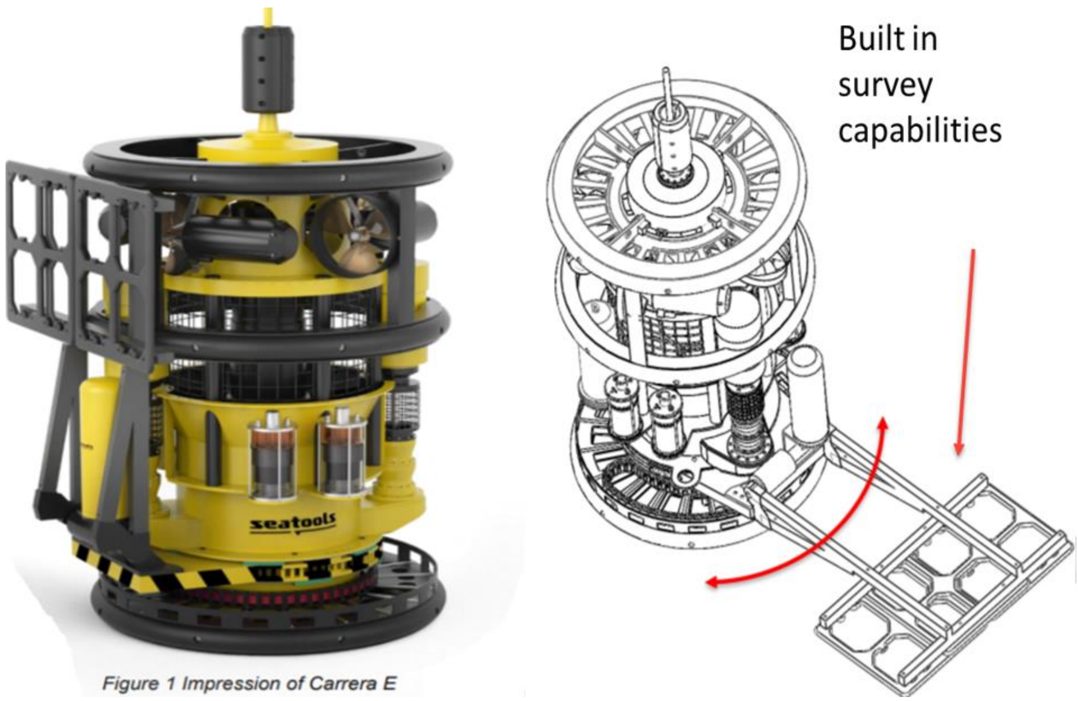

Figure 48. Sea Tools Carrera E Dynamic Excavator For Clearing Out Between the Conductors and Debris

It is estimated that with 3 dredges at 120 cubic yards per hour each would be able to excavate the required volume in about 90 days.

REDACTED
[redacted]

- Re-establishing connection to the wells.

In order to re-enter the wells after excavating to gain access to the damaged wells, a connection must be re-established to the well.   While performed by a few specialized firms with expertise, these are common types of operations that have been performed hundreds of times in the Gulf of Mexico alone.   Several firms with experience in this area were engaged to assess the viability to re-establish the connections to the wellhead. These firms had experience with many downed platforms and associated damaged wells destroyed by hurricanes in the Gulf of Mexico from hurricanes in 2004 (Ivan), 2005 (Katrina and Rita), and 2008 (Ike). The oil industry responded to the platform removal and well abandonment work for several years after each hurricane with experienced teams and new investment in equipment. Most of the well intervention work was done through top access after cutting and removing debris.

Excavation will give access to the exposed conductors and tubulars and provide a safe working area for any needed diving operations.

REDACTED

[redacted]

Based on experience with hundreds of wells, it is typical to find the wells in a variety of conditions and the same is expected in the MC – 20 case. Some of the possibilities:

- Christmas Tree, Wellhead and Tubing Spool Intact with all valves in place
- All pressure control devises sheared off with exposed tubing and annular spaces, bent and crimped tubulars
- Anything in-between

Typical operations involved in re-establishing connection to the well involve:

Investigation of well connection condition, i.e. valving, tubing heads, wellhead, tubing configuration, annuli.   This will help to determine next steps.

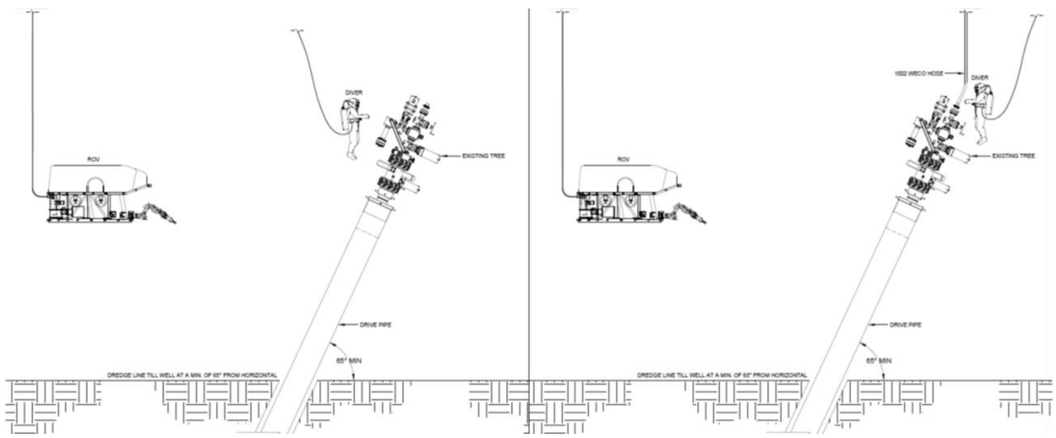

Figure 50. Diver with ROV Investigating Condition of Well

Hot Tapping and Killing any pressure on the tubing or annular spaces.   A hot tap device provides a secure seal on the tubular in question and can drill into multiple tubulars exposing any pressure in a controlled manner. The pressure is then effectively killed with the injection of a heavy fluid.

Figure 51. Hot Tap Tool

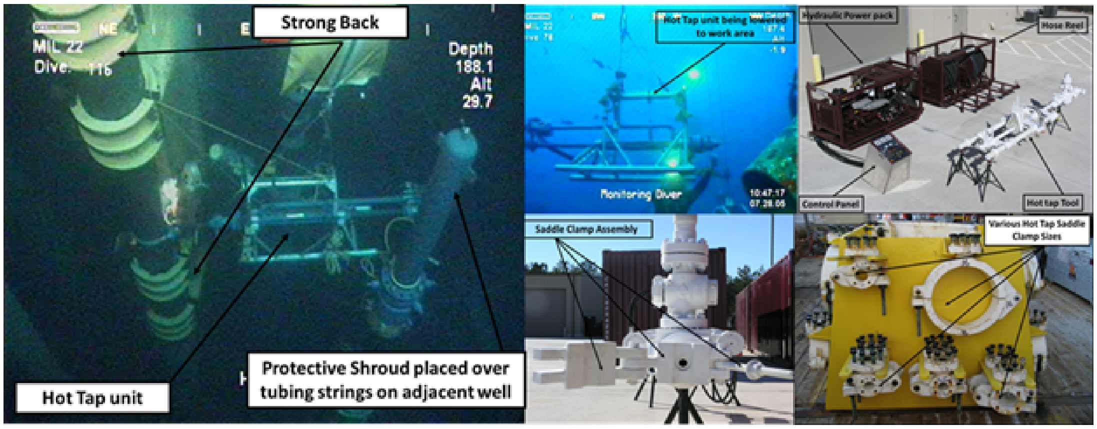

Figure 52. Sub-sea Hot Tap Equipment – On shore and at work under water.

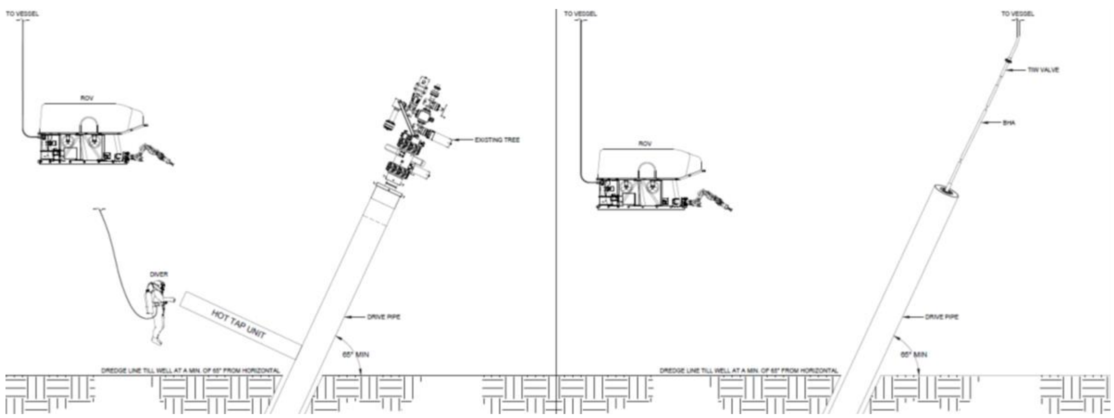

Figure 53. Hot Tapping to Kill Any Pressure

It should be noted that hot tapping operations are designed for and many times performed under high pressure situations. While all precautions for pressure will be taken at MC 20 wells, these are not perceived to contain high pressure rather it is envisioned that the wells are exposed and flowing.

Once the well is killed with the heavy fluid, a new connection must be established in a process is called “Wedding Cake Operations”. In Wedding Cake operations, it is necessary to gain access to desired annular spaces and tubulars, casings will need to be cut and stripped, which can be done with a Diamond Wire and Rail Mill.

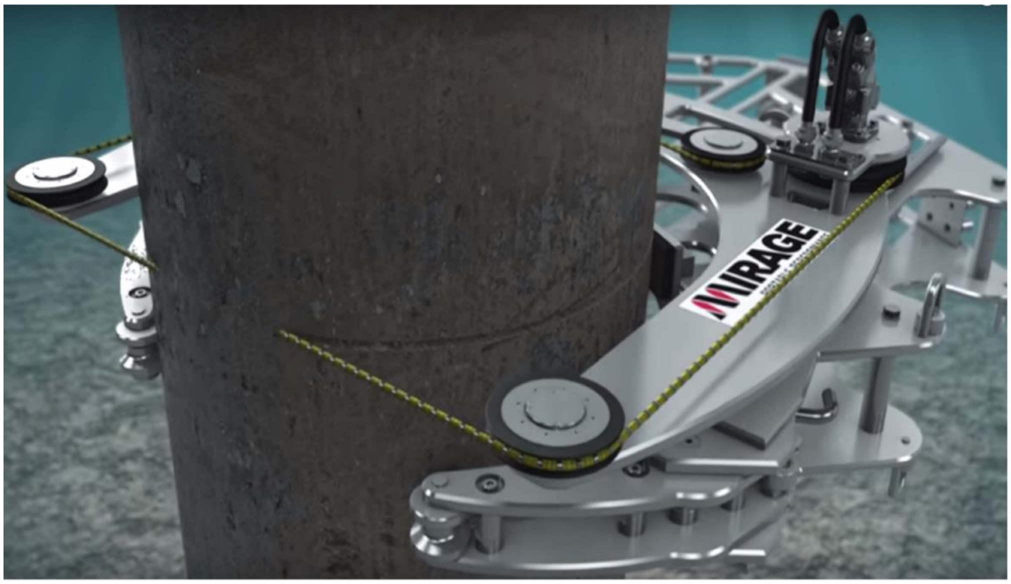

Figure 54. Diamond Wire Saw

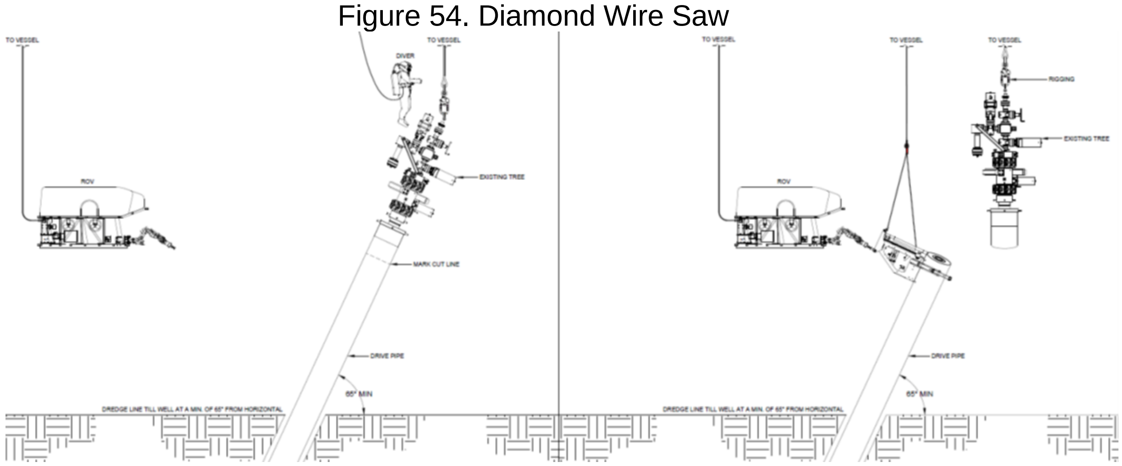

Figure 55. Diamond Wire to Cut Old Wellhead/Tubulars and Expose New Area for Reconnection

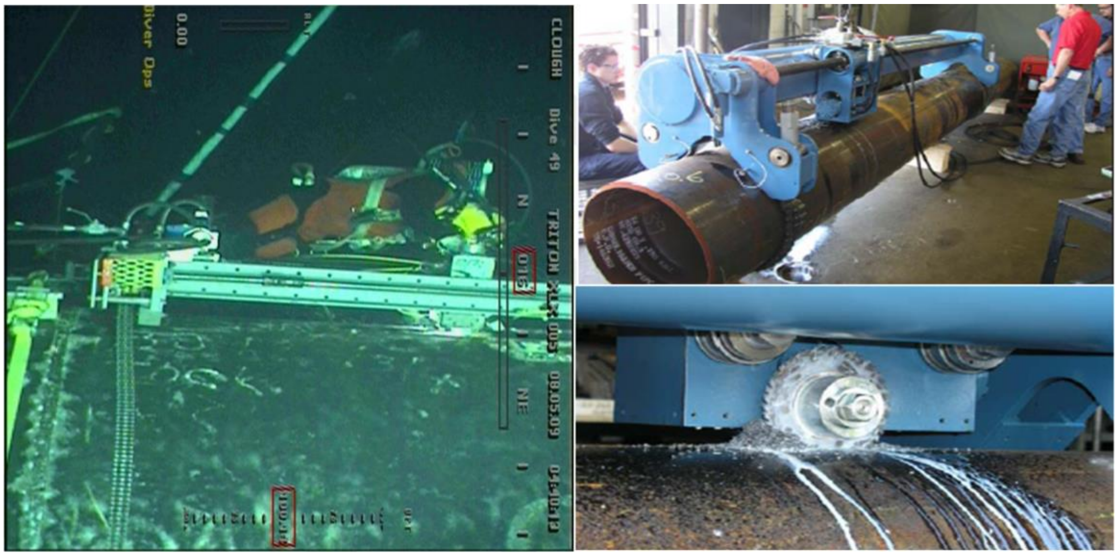

Figure 56. Rail Mill Used to Cut Off Outer Tubulars and Gain Access to Desired Inner Strings

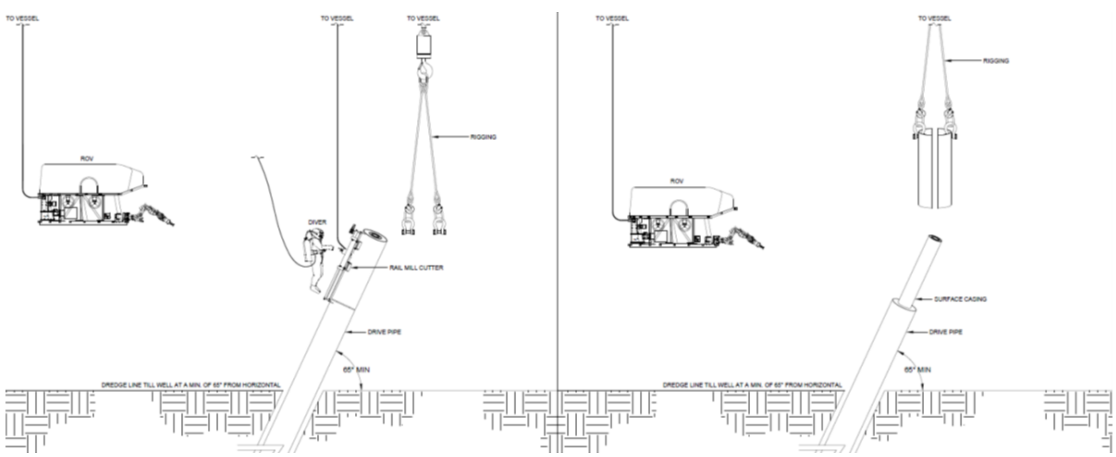

Figure 57. Rail Mill Exposing Tubulars and Annular Space for Reconnection

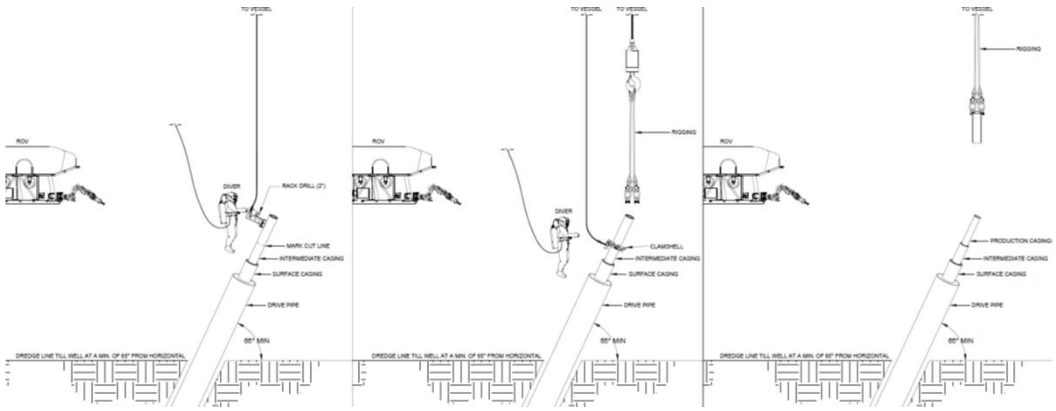

Figure 58. Desired Configuration

The process is repeated until desired configuration is achieved, notice the casing are now formed in a “wedding cake” type of configuration.

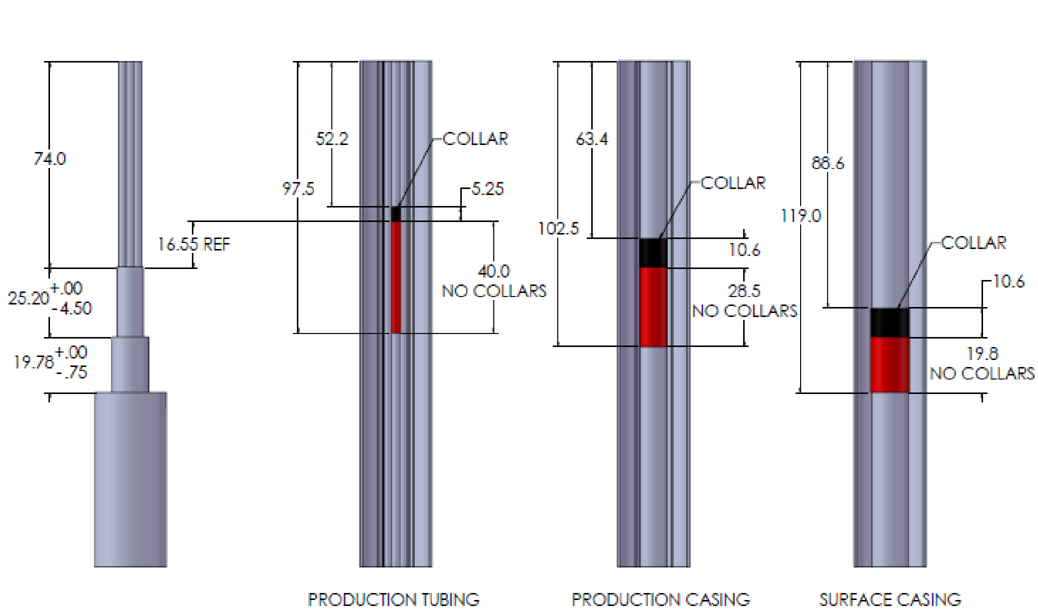

Figure 59. Alternative View of "Wedding Cake" Removing Casings from Right to Left to get to Production Tubing

Graphic - An alternative view of Wedding Cake” removing casings from right to left to get to the production tubing.

Once the Wedding Cake is performed a new wellhead is lowered and re-attached establishing an integral connection to the well. (see below).

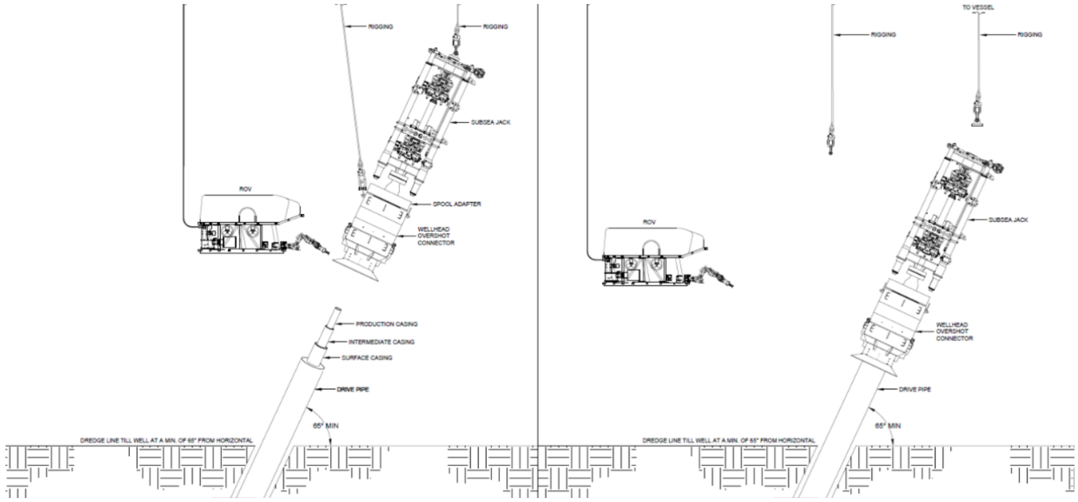

Figure 60. New Wellhead Lowered and Re-Attached

In this configuration the well can now be accessed and abandonment operations can proceed. (see photo below from leaners and downers, wells with re-established connections.

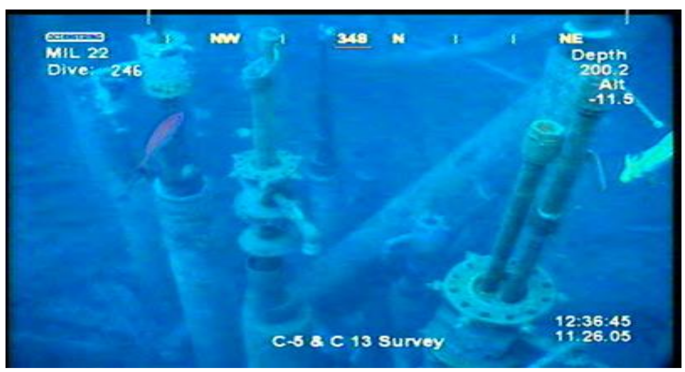

Figure 61. Photo with Re-established Connections

- Entry into the wells and setting plugs to secure the source and/or properly abandon all zones, per 30 CFR 250-1715 standard.

  The following types of operations were investigated with specialty firms to access the wells and perform intervention / abandonment operations.

  - Wire line intervention
  - Coil Tubing intervention
  - Snubbing intervention

While all of these techniques can be used to re-enter the well and perform abandonment operations, each one has its own advantages. It is not perceived that there will be a one size fits all solution and that multiple techniques will be employed depending on what is found during the diagnostic phase or upon what is encountered during actual operations. For the purpose of this report Wire Line and Coil Tubing will be shown.

Riserless Wire Line Intervention

Operations are supported from a vessel that is fully equipped with a vast variety of wireline tools to perform the needed well entry, diagnostic and well abandonment operations. The lubricator (prepped for tools) is run from the vessel and connected to the subsea wellhead. Valves may be actuated via hydraulic lines (MUX system) to open, close and functioned to allow for tools to pass through into the wellbore.

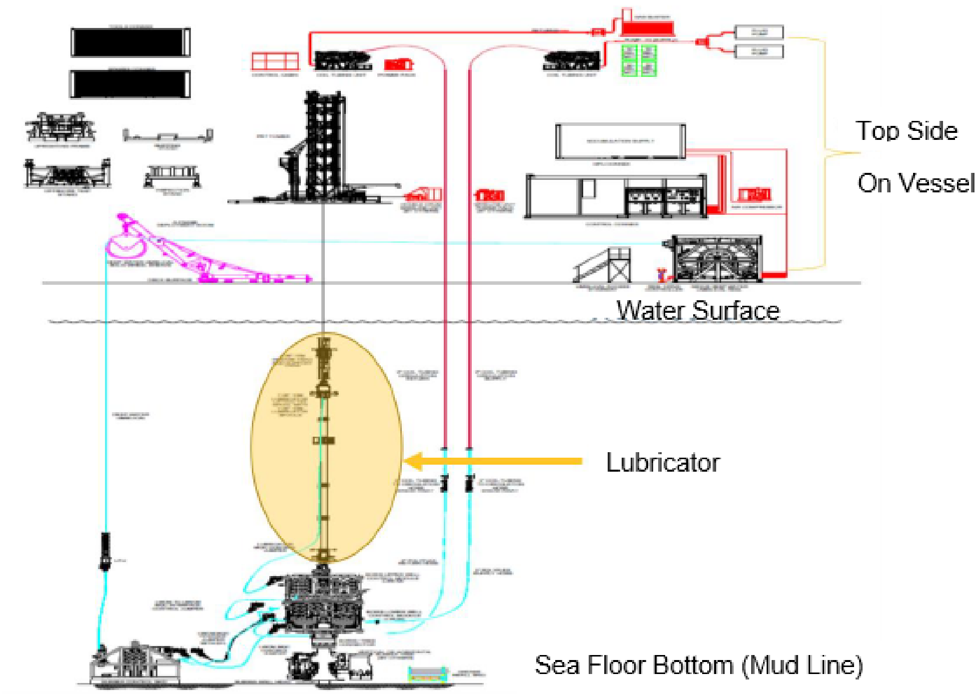

Figure 62. Riserless Wire Line Intervention

The wireline units remain on the vessel's deck. These systems can be designed to operate without any diver support.

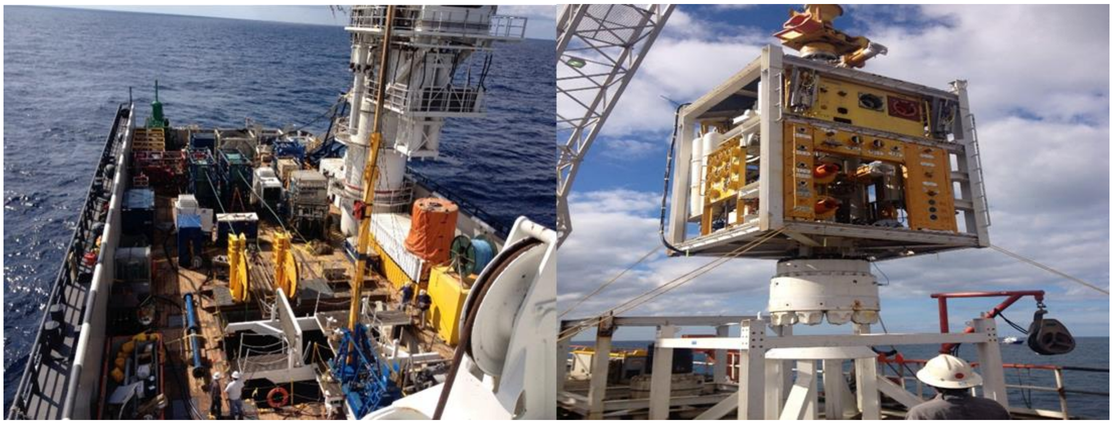

Figure 63. Riserless Intervention System Equipment

The photos above show an actual Vessel deck spread for subsea wireline operations (Left) and the Riserless Intervention System, / light well intervention BOP being lifted to go overboard (Right).

Of note, the firm Blue Ocean / Oceaneering International has run over 1,900 total Riserless Wireline Intervention Runs at the time of this report. Once the connection is re-established, these operations become quite standard and have been performed for years.

REDACTED [redacted]

<u>Coil-Tubing Intervention</u>

Coil tubing has some inherent advantages over wireline operations; e.g.

- Ability to pump fluid through the coiled tubing
- Ability to attach tools that can be used to drill, mill and other functions
- Much higher tensile strength and ability to push past potential obstructions

While coil tubing has been used for offshore operations, there is limited experience with riserless subsea operations.   Also, for MC 20 it would be convenient to have a horizontal subsea package to reduce the radius of curvature needed to gain access into potential horizontal or near horizontal wells.

Cudd Energy Services has already designed and used a horizontal subsea riserless Coil Tubing Unit developed for and used on the Ehime Maru Project in 2001.   This application and design involved deploying the horizontal coil tubing unit in 2,400 ft of water on the sea bed and then using the 2-3/8” coil tubing to drill under the sunken Ehime Maru.

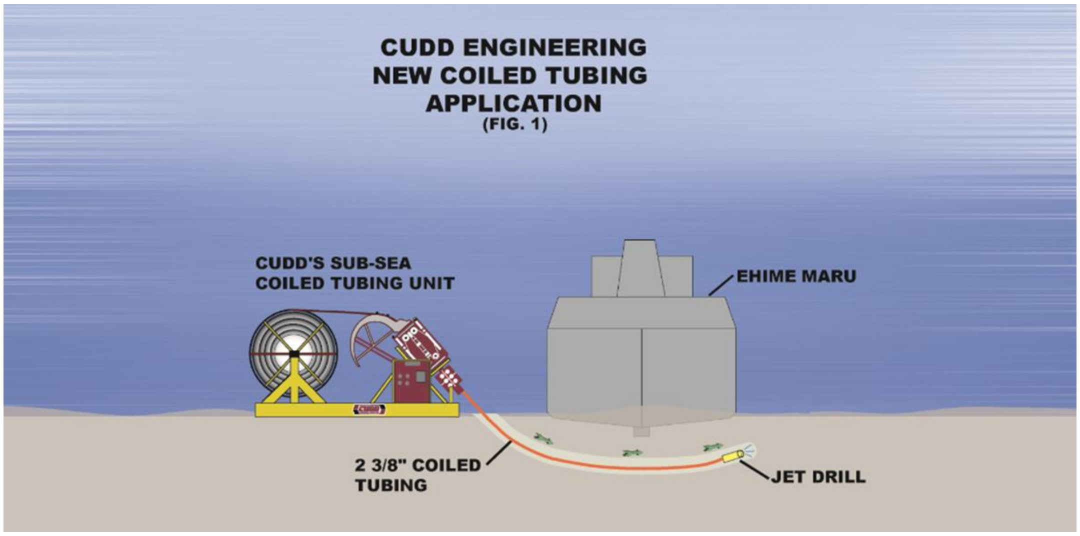

Figure 64. Horizontal Subsea Riserless Coil Tubing Unit

Figure 65. Subsea Horizontal Coil Tubing Unit

The concept which has already been proven would need to be modified for the MC 20 project, which is in substantially shallower water – about 400 ft or almost 2000 ft shallower than the Ehime Maru Project and would be used in a much more traditional application, well intervention.

REDACTED

[redacted]

As with the wireline application, once a connection is established entry and abandonment operations become quite standard.

Coil Drilling Technologies (CDT) performs slim-hole directional services in multi-bench and multileg horizontal applications. This innovative coil steering technology provides increased directional control and can be deployed on a variety of e-coil reels.

<u>Typical Coil Tubing Applications:</u>

- Setting Plugs & Abandonment Operations
- Milling, Cutting & Fishing Operations
- Setting whip stock Multilateral navigation
- Directional drilling & Logging runs
- Casing exits
- Cleanouts
- Lateral extension
- Open-hole sidetracks
- Stimulation

Like Wire Line a vast variety of tools would be made available to deal with multiple potential scenarios encountered with the wells. It should be noted that each of these firms have specialty tool divisions that can rapidly react to challenging situation and rapidly manufacture custom tools.

2. Intersecting Intercept Wells

A planned well intercept (or intercept well), as related to the oil and gas industry, can be defined as one or more boreholes that are directionally drilled with the intention of geometrically intersecting a second or multiple boreholes to achieve a specified objective.

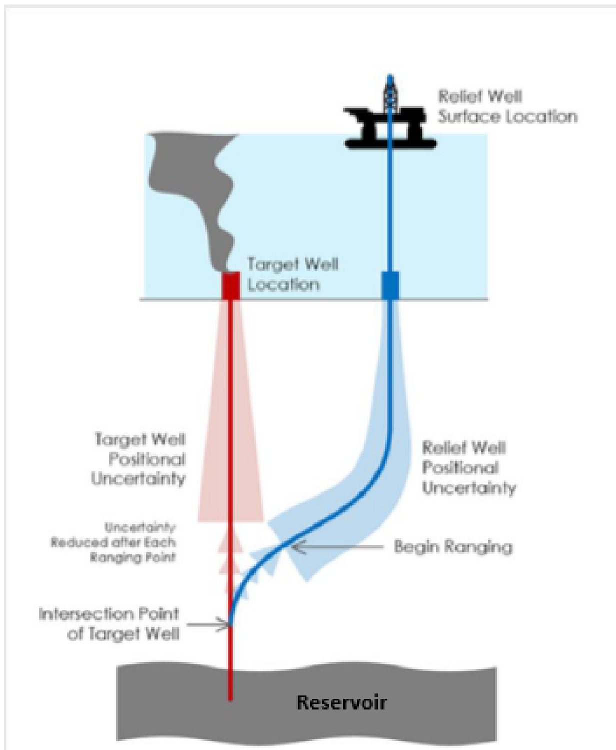

Figure 67. Target Well and Intercept Well Concept

Wellbore Intercept is a broad topic which covers a range of technologies, methods and domain expertise to deliver desired objectives. The objective for making the intersection, the local operational conditions, and available technology and expertise will dictate the well intersection design process. Although there are many similarities, such as the basic geometric design and drilling equipment used, designing and executing these wells requires expertise in the various specialized methods and equipment used to achieve the objective. The Industry Steering Committee on Wellbore Survey Accuracy (ISCWSA) published the Well Intercept Sub-Committee Book. This book, which can be accessed via the REDACTE is an excellent source for novice as well as oil & gas engineers alike.

REDACTED

As explained and evidenced in section 3.4 of this report none of the 9 intercept wells drilled by TEC have achieved any of the abandonment requirements. The TEC parallel intercept well strategy was wrought with uncertainties and risks. In fact, even an effective intercept well that actually intersects the target and is able to pump cement into the completion, would not meet the standard. It would also not allow for testing of the cement plug nor would it provide source control for any of the upper sands with the potential to flow. (see Findings 3.2 through 3.4 in this report).

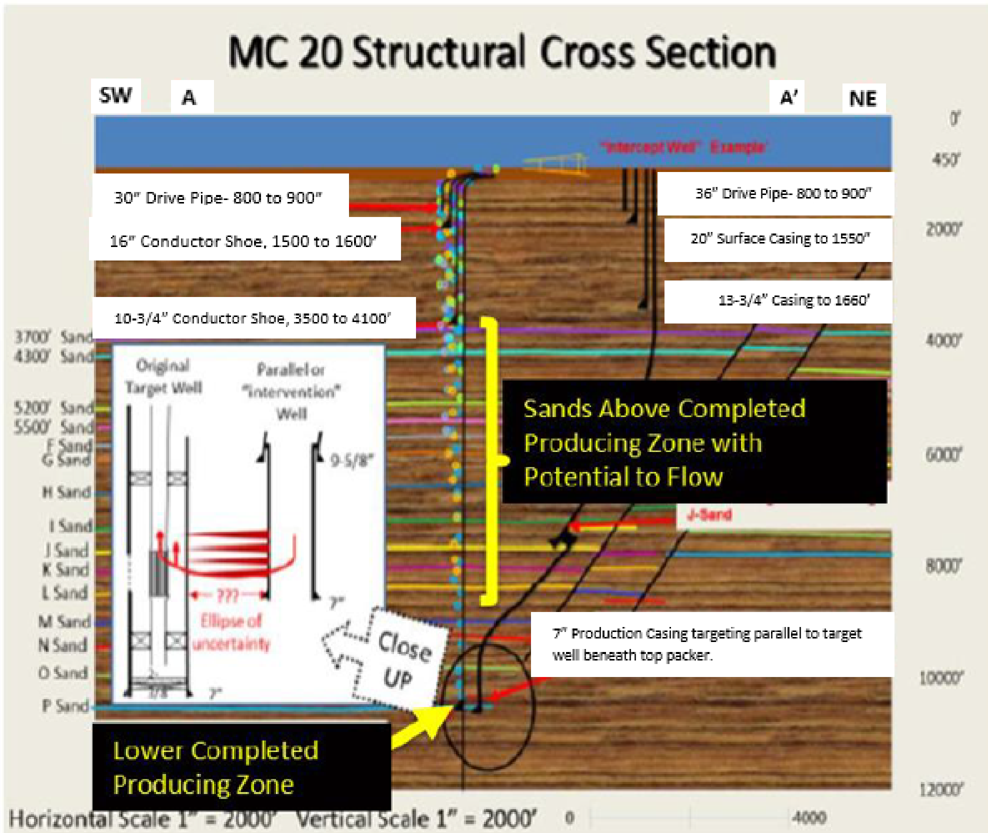

Figure 68. MC 20 Structural Cross Section depicting *TEC Parallel Well concept which attempted to target the lower completed producing zone (see finding 3.4 for issues with this application for MC 20 wells). Also shown are the upper sands with potential to flow through multiple integrity issues identified in findings 3.2 & 3.3 of this report.*

As with other options to achieve source control and/or abandonment, Couvillion conducted reviews with FISTE. Both Wild Well Control (WWC) and Cudd Energy Services were selected to provide expert opinion, advise and conceptual plans for the intercept well option. Couvillion briefed both companies on previous efforts by TEC to drill and intercept 9 wells between 2009 and 2011. Both companies agreed that TEC approach to parallel the target wells, run casing and then attempt to perforate into the target well was not preferred and would not be successful.

Both companies proposed to intercept the wells by actually intersecting the corresponding target well. While this approach was deemed viable for the completed producing interval, it still did not address flow from any upper sands that have potential to flow through the vast integrity issues to surface. It is certain that upper zonal risk to flow would remain and departures would need to be granted from the standard if this option was used as a stand-alone option.

The art of locating a well is known as ranging. The third party firms would use ranging technology to location and intersect the target well, there exist different types of ranging techniques (see image below and refer to the ISCWSA Well Intercept Link above for more details).

Figure 69. Ranging Target to Well

While ranging technology has been used for many years and is very reliable, it does have some challenges. Ranging is not exact as there are uncertainties associated with well positioning and while well positioning has improved over the years, MC 20 wells have high directional profiles and were drilled in 1980's and 1990's when uncertainties were greater. Also, ranging relies on having contact with the metal casings in the ground; however, when there are 2 or more wells in near proximity traditional ranging devises cannot discern which well is the target well and which is not. This presents two rather distinctive issues with the MC 20 location and wells.

1) The upper sections of the wells pretty much go straight down to around 3000 ft and are highly congested. When the wells do begin kicking off, multiple wells go in the same general direction until much lower. The configurations of these wells make it challenging if not impossible to use traditional ranging to intercept a well high enough to set a plug above the upper sands with potential to flow.

2) The 9 parallel intercepts wells drilled by TEC which did not stem the flow of hydrocarbons were drilled within close proximity to the target well at the lower completed zone making it near impossible to discern which well is which. (the

target well or the intercepts drilled by TEC). To further confound matters, TEC decided to abandon the 9 intercept wells cutting the wellheads off below the mudline, i.e. these well are now unusable to go back in to perform proper abandonment plugs in the lower zones. Had this not been done, it would be possible to re-enter these wells and either perform side-track operations or use current to identify which well is which.

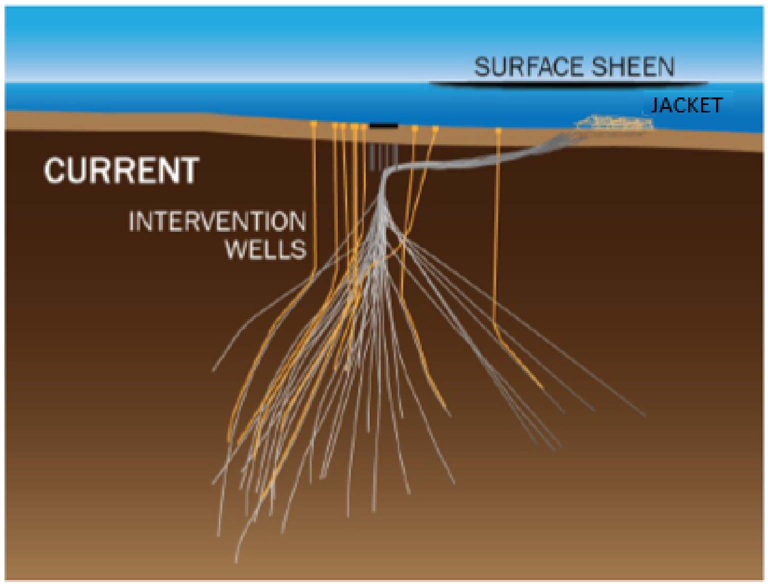

Figure 70. Cross Section Graphic of Wells in MC 20 Field showing the proximity of the wellbores, Yellow Wells are the 9 TEC Intercept Wells.

As an example of the complexity of this operation; while drilling intercept wells, TEC accidently intersected the wrong well and lost 369 bbl. of drilling fluid (see section 3.4 for more details). While there would be many challenges and risks to intersecting a desired target well in the MC 20 field, both FISTE (WWC And Cudd Energy) believe that each well can be intersected.

Another challenge is determining the location of the intersection point and what to do once the well is intersected. See below diagram for some of the different configurations of completions in the MC 20 wells, not shown are the dual completion wells. Each of the type of completions is approached differently to best set a plug to attempt to isolate the completed producing interval. Additionally, for the wells targeted by one of TEC's 9 parallel wells it is highly unlikely that a successful intersect can be achieved near the completed interval; the intersection point would have to occur much higher where separation from TEC intercept well allows for ranging to locate the target well.

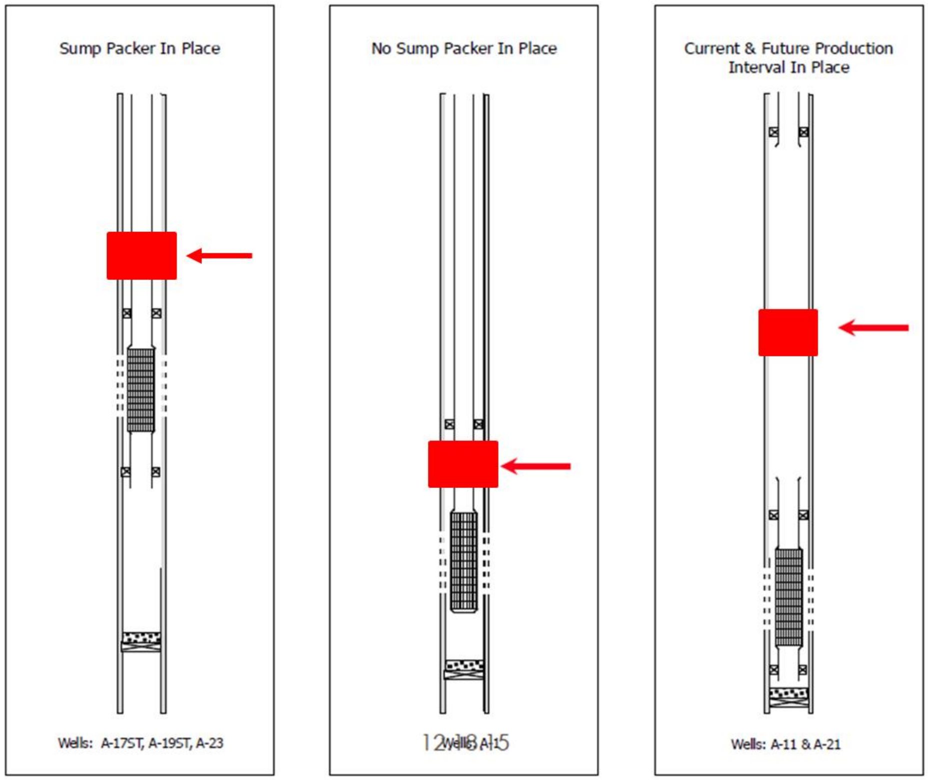

Figure 71. Common Well Completion Configurations in MC 20 Field

Once ranging enables contact with the target well, casing can be set above the intended intersect point to mitigate against stuck pipe. A specially designed concave mill would then be run to first score and then preferentially guide the mill into the casing (not bounce off of it and return to formation). A fishing or watermelon mill would follow to mill out an entire section of casing and tubing providing space for an earth-to-earth cement plug to be set, effectively plugging and sealing off the lower zone. Some risks and challenges encountered during this type of intersect approach are the ability to mill into the casing, dealing with inner tubing/s, stuck pipe, losses, poor cement bonding and other issues; each of these potential issues needs to be considered, planned for and addressed with contingencies.

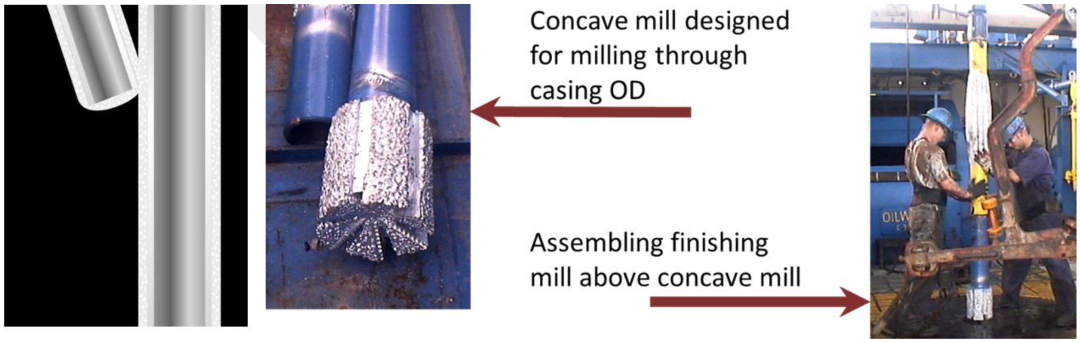

Figure 72. Different Type of Mills for Milling into Casing

Figure 73. (Left) Milling into Target Well. (Right) Pumping Cement into the well to create an isolation plug

The ability to establish a communication path for setting isolation / abandonment plugs and testing the plug would also be a big challenge, however some innovative conceptual approaches were discussed, e.g. employing dual intersections to set two isolation plugs.

Two approaches to dual intersects are shown below.

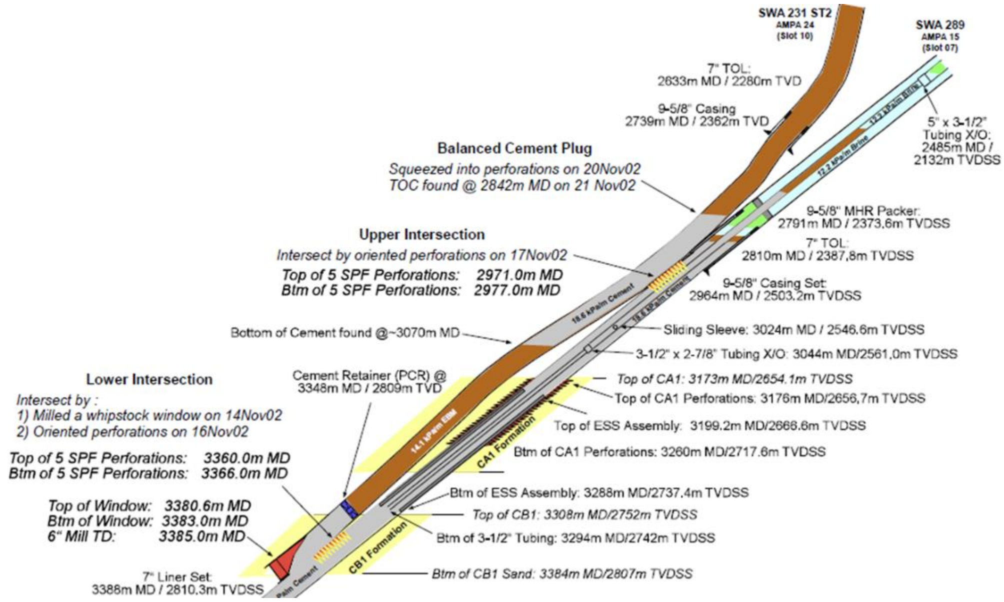

Figure 74. Concurrent Intercepts Concept
Note – figure above is only to show two intercepts (verbiage not important)

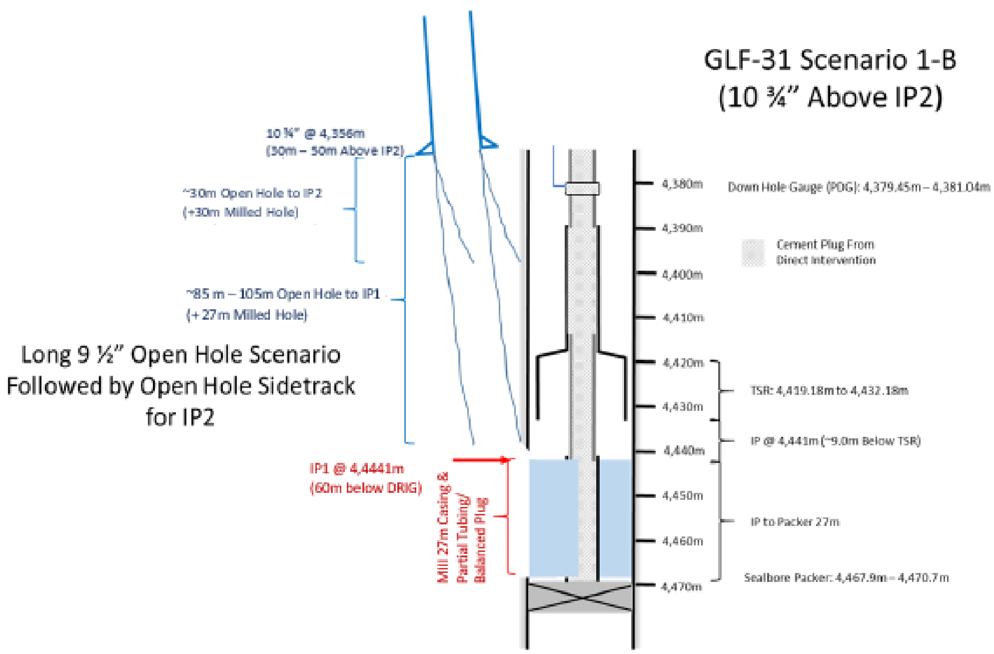

Figure 75. Sequential Intercepts (Side Tracks)
Note – figure above is only to show two intercepts (verbiage not important)

It is perceived that this option in conjunction with the Excavation, re-establish connection to the well and access the well would provide the most assurance of achieving the source control and/or the abandonment objectives.

Also, while both companies felt that it was feasible to intersect and set a bottom plug, they also recognized several challenges to the approach that are would need to be addressed in the next phase during front end engineering design (FEED):

1) The 9 wells targeted by TEC to intercept between 2009 and 2011 (Parallel Strategy) are likely to cause interference with any ranging techniques.
2) Milling into target well production casing and ability to establish communication path for cement plugs / isolation.
3) Milling into target well production casing and ability to set mechanical plugs.
4) Dealing with production tubing to set effective barrier plugs.
5) Ability to test a barrier plug.
6) Ability to intercept into casings with upper potential flow zones.
7) Perceived departures to 30 CFR 250.1715 Well Abandonment Standard and Requirements

For a more detailed review of risks, see the risk assessment for intercept wells in the Risk and Option Ranking Section.

3. Depletion

The depletion option entails continuing with the current containment system which is separating, collecting and storing approximately 27 bbl. (1260 gal) per day of oil from multiple wells and reservoirs in the MC 20 field. The oil is stored and taken off to sales approximately every 3 weeks. At the time of this report there have been 10 “pump offs” of off takes with over 6,282.1 bbl. (263847.8 gal) of oil taken away from the site. The current spill rate equates to about 11,000 bbl. (460,000 gals) of oil per year.

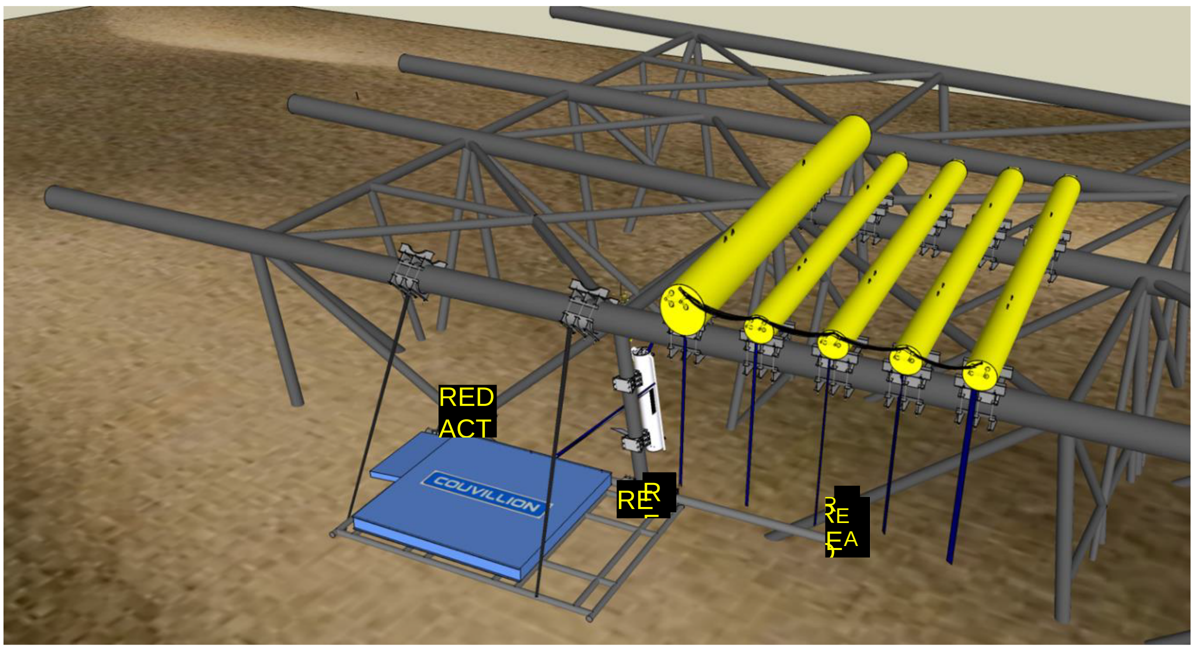

Figure 76. Depletion Option

It is estimated that depletion would take between 50 and 100 years and possibly beyond. It has also been recognized that the MC 20 reservoir is aquifer supported and that this type of drive mechanism will continue to re-pressurize. The pressure can potentially build back to initial reservoir pressure. Couple this with the fact that the tubulars in the wells will continue to erode and fail, it is not a matter of if only when new plumes show up. Also, the current containment system will require ongoing maintenance and eventually need to be replaced (deign life is estimated at 10 years).

During the risk ranking and option ranking process and session this option was deemed to have serious and critical safety & environmental risks associated with it that were outside the window of safe and viable operations (see Risk and Option Ranking Section Details).

However, risk greatly reduced for a 3 to 5-year use which would be an acceptable use of this option while simultaneously employing other options for achieving source control and/or abandonment.

In each of the options, the environmental risk of damaging the current containment system and/or new plumes occurring was identified. A mitigation to this risk is to have a mobile containment dome ready at the dock for deployment should such a situation occur. REDACTED

REDACTED

REDACTED

4. <u>DEPLETION WITH ACCELERATION</u>

This option entails drilling new wells and installing infrastructure as a means to accelerate depletion by producing the oil & gas in the field, while continuing with option 3 (depletion).

As the spill rates were not known at the start of the project, it was perceived that it may have been possible to produce the field and pay for this option and the abandonment.

However, installation of the rapid response system and understanding the rates and going through the rigorous risk and option ranking process, this option is not viewed as a safe or viable way forward.

<u>Summary of Issues with this option:</u>

Beside drainage of the reservoirs, depletion would require a sequence of surveillance and mitigation measures aimed at minimizing the risks of uncontrolled hydrocarbon discharges, as follows:

a. Monitoring of pressure recharge data for the produced MC 20 reservoirs through one or more newly drilled, and dedicated Observation wells, followed by

b. Pressure depletion, through production of one or more of the MC 20 reservoirs, selected on the basis of the Pressure Surveillance results.

   - Any depletion would need to have strong aquifer support along the ability to drill up dip in the reservoirs. Additionally, new and previously unproduced sands would probably need to be accessed to fully deplete the reservoirs. Note – there is risks that sands may be cross-flowing.

c. Several observation wells would have to be drilled. Defining the number of wells and their targets would require a subsurface evaluation beyond the scope of the current work. However, it seems quite feasible to collect sets of pressure measurements per reservoir, for multiple reservoirs, in a single penetration, using repeat formation tester (RFT) type measurements in logging while drilling (LWD) mode. Still, given the scatter of reservoir footprints, a very preliminary estimate of 5 penetrations (wells and/or long sidetracks) would be required in our view, to test all the produced reservoirs.

d. The criteria for selecting the depletion targets would have to be defined quantitatively, in terms of risk tolerance and level of recharge.

e. Production wells would have to be drilled and completed to deplete every reservoir identified as a potential leak source based on the pressure recharge data. It would be difficult to estimate the number of production wells required until after the pressure data has been collected.

f. Production handling facilities would need to be put in place and operated. There are some inherent risks with such facilities:

   - Fixed jacket type facility would be subject to the same problematic mudslide and existing unconsolidated soil conditions currently at the site.
   - A floating type facility would be challenged with weather conditions, such as hurricanes and would need a quick disconnect.

g. Any facilities built and operated would need to eventually be decommissioned. All new wells that have been drilled plus the existing 25 wells would have to be plugged and abandoned to the standard once the field has been depleted.

5.0 DATA GAPS AND CLOSE OUT PLAN

As part of Task 8, the team was charged with identifying and proposing an assessment approach to close the data gaps; including all possible options to achieve plugging and abandonment standards using well intervention and/or reservoir depletion.

The following data gaps were identified by the team. The gaps were categorized into:

- Hydrocarbon (Oil & Gas) Analysis
  - Volumes
  - Sample Analysis
  - Sheen over time review
  - Plume over time review

  As the Responsible Party asserted that only between 1 to 4 gallons per day were causing the sheen and that the hydrocarbon was from Biogenic source (not reservoir), it was necessary to verify the amounts of Hydrocarbons flowing at MC 20 site and that these fluids were coming from the subsurface source, through the wells and to the surface. See Finding #1 for results. **This gap has been Closed.**

- Technology to image and locate the conductors and tubulars buried under the mud

  See Section 4.4.2 for further details on the closure of this gap.

  While the technology trial was performed and the technology was proven successful, this survey work provided just a small sample. It does not yet provide a complete enough picture to resolve the depth, location and configuration of the conductors and tubulars required reduce the uncertainties in the excavation and intervention options. Expanded field wide scans are needed to gain the level of detail and needed information to develop refined & robust excavation, reconnection to wells and intervention plans.

- Excavation & Soil Analysis

  Proposal for closing gap - Geotechnical soil data reports were issued in 2005 and 2007 and have been analyzed by Couvillion contracted subject matter expert (SME). Initial results were reviewed with a soil's engineering firm during market research to evaluate excavation options. A scope of work was issued for a study to develop conceptual options for excavation. The sub-bottom conductor imaging survey will feed into this study to give realistic options for excavation at the site to access the conductors. (See Section 4.4.3 Option 1)

REDACTED [redacted]

The team also identified the following data gaps, which were viewed as "nice to have" for the purpose of this report and would be very useful for the purpose of executing the long-term abandonment plan. It is recommended that the operator hand over this information to whichever party is granted approval to execute options to secure the source and/or achieve the abandonment standard.

Information and Reports from the Operator:

- Well Reports
  - Drilling, Completion & Intervention
  - Corrosion Logs
  - Well Testing Reports

- Pre-incident by well:
  - Flow Rates
  - Flowing and shut in Pressures
  - Fluid type/s and any water cut
  - Annular pressure

- Post incident reports, photos, diagrams of Platform and Tubulars (assess condition of wells).

- Pre-incident Field Data by Reservoir & Sand
  - Access to any Oil/Gas/Water samples
  - API, Gas Composition analysis
  - Original Pressures and Draw Down Pressures
  - Original Volumes in Place and Draw Down Volumes

6.0 TASK 8 & TASK 9 DELIVERABLES

Task 8: Couvillion and its sub-contractors working with the Source Control Support Coordinator and the Source Control Branch Director will begin a review of relevant site data and reports to support a review of long term sub-surface source control operations, and propose an assessment approach to close the data gaps; including all possible options to achieve Plugging and Abandonment standards using well intervention and/or reservoir depletion.

- **Deliverable 8:** Within 60 days of mobilization, Couvillion and its sub-contractors will provide an assessment of the gaps in the available data set for sub-surface source control operations, and propose an assessment approach to close the data gaps to the USCG.

Task 9: Couvillion and its sub-contractors working with the BSEE and the Source Control Branch Director (SCBD) will use available data and market research to identify viable options for sub-surface source control operations including well intervention and/or reservoir depletion to secure the source and/or achieve Plugging and Abandonment standards.

- **Deliverable 9.1:** Within 90 days of mobilization, Couvillion and its sub-contractors will complete an assessment report of the possible sub-surface source control response options for securing the source and/or achieving Plugging and Abandonment standards. The report should include risk ranking (severity, probability, exposure), likelihood of success, and failure modes.

- **Deliverable 9.2:** Within 90 days of mobilization, Couvillion and its sub-contractors will present the possible sub-surface source control response options for securing the source and/or achieving Plugging and Abandonment standards to the USCG, BSEE, State On Scene Coordinator (SOSC), and Scientific Support Coordinator (SSC).

7.0 FRACE REPORT:

As mentioned in the background section, the team was given access to the FRACE report. This report gives the impression of presenting a series of conclusions and findings on behalf of the Unified Command surrounding the event and its after effects.

The team found the FRACE report to contain apparent biases, especially in many key assertions that are not supported by the underlying data or where certain assertions use assumptions or a series of assumptions that the team viewed as beyond reasonable. There are other instances in the FRACE report where key assertions and conclusions are factually incorrect.

As an independent reviewer, the team is obligated to raise concerns over this report. It is also necessary in that the team's key findings contradict the FRACE report and support an alternative series of recommendations for long term abandonment options.

This section points out just some of the key issues found in the FRACE report.

1) **<u>The document is presented as representing the Unified Command</u>**

The cover of the FRACE report has in the title, "Unified Command Summary" (See below), however the team could not find any supporting documentation that anyone outside of Taylor Energy actually signed off or endorsed the document.

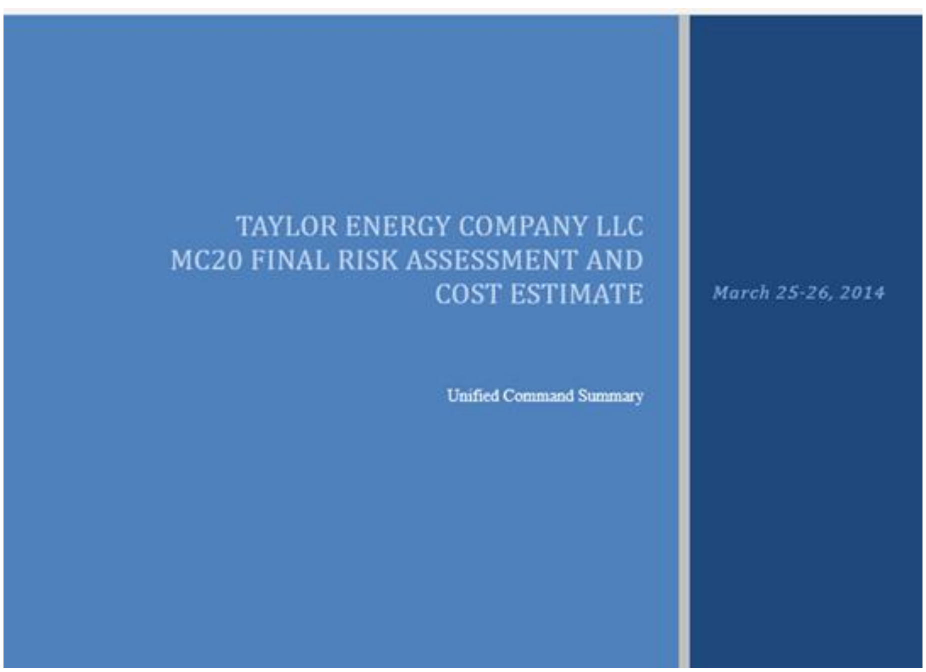

Figure 78. FRACE Report Cover Page

2) Assessment of 9 intercept wells and effectiveness of abandonment

Taylor's Assessment:

"All nine wells that had the potential to flow significant rates of hydrocarbons were plugged as a result of well intervention operations.

To date, the Interior agencies have authorized, and Taylor has successfully completed, decommissioning activities for: (1) the platform deck; (2) the pipelines; (3) debris removal; and (4) plugging and abandoning 9 wells by drilling intervention wells."

Task 8 & 9 Response:

The above assertion is not factual, See Finding #4 in this report.

3) Assessment and assertion surrounding volumes of HC being released into gulf

Taylor's Assertion:

"At present, there continues to be a low volume hydrocarbon release at the site, resulting in a sheen expression on the surface, averaging less than 4 gallons per observation. The rate of release equates to approximately one drop of oil being released each minute from a two square foot area on the mud line. There are occasional larger surface expressions of hydrocarbons. The source or cause of these irregular but periodic larger surface expressions (still reflecting gallons, not barrels) has been linked to the lunar cycle and the influence of tidal movements."

Task 8 & 9 Response:

The above assertion is not factual, See Finding #1 in this report.

4) Assessment of Gas at Surface is due to Entrained Hydrocarbons

Taylor's Assessment:

"Analysis has been performed showing that the gas source recovered by the containment system near the buried platform jacket is biogenic. The U.S. Coast Guard Marine Safety Lab has provided analysis concluding that there is a definite match between the sheen and the hydrocarbons in the soils. Multiple sonar surveys over the last few years have confirmed an absence of any plumes remaining in existence."

Task 8 & 9 Response:

The above assertion is not factual, See Finding #1 in this report.

5) Assessment on containment

Taylor's Assessment:

The FRACE report dedicates over 14 pages (p. 71 through p. 85) with links to 35 separate studies and reports concluding:

"Even if UC command requires TEC to move forward and re-install the newly modified containment system in an attempt to fully eliminate this minimal sheen, TEC's analysis would suggest that total sheen elimination is not likely to result and that further containment applications should then be suspended with the focus shifted to future mitigation rather than continuing to pursue futile attempts for a sheen with no observable (or modeled) ecological impact."

Task 8 & 9 Response:

In fact, Task 8 and 9 Interagency Work Group commissioned Couvillion Group, LLC to develop and implement containment strategies and tactics that eliminate the surface sheen at the MC 20 site. Couvillion successfully designed and implemented a subsea containment, separation and storage system that is currently capturing and processing an average of 1,000 to 1,300 gallons of Oil per day from MC 20 site. The surface sheen has materially reduced as have any adverse effect to the environment from the captured oil, See Finding #1 in the report.

6) Assessment that nothing can be done to plug & abandon wells

Taylor's Assessment:

"The decommissioning work being performed at MC 20 is unrivaled in its complexity. Conventional plugging and abandonment of the wells was not an option due to the sheer volume and consistency of overlying mud and sediment, the tangled web of wellbores left in the wake of the regional slope failure, and the environmental risks posed by these factors.

Both TEC and MMS recognized the impossibility of pursuing conventional plugging operations. While conventional plugging and abandonment of wells typically proceeds by reentering the target well from the surface, maintaining well control, and inserting cement plugs, the MC 20 wellheads are mangled and submerged under vast quantities of mud and sediment—making them inaccessible.

Additional intervention wells have been extensively discussed and considered. It is the conclusion of every individual, group or organization considering the issue that further intervention activity poses greater environmental risk than any potential environmental gain a very real risk exists for an uncontrolled discharge in the event of further activity. Containment is the only viable environmental response."

Task 8 & 9 Response:

No documentation could be found supporting the conclusion that every individual, group or organization considering the issue that further intervention activity poses greater environmental risk than any potential environmental gain a very real risk exists for an uncontrolled discharge in the event of further activity. See Task 8 & 9 report recommendation for plugging and abandoning the wells to the standard.

7) Assessment of Reservoir Potential to Flow

Taylor's Assessment:

"Based upon numerous studies and assessments, most of these 16 wells are not only prevented from flowing as a result of the increased hydrostatic of the seawater bearing down on the reservoir, but most also have sealing plugs created by the sediment carried by the seawater that entered the wells and flowing into the depleted reservoirs."

Task 8 & 9 Response:

The above assessment is misleading at best and uses a series of unrealistic assumptions to produce a No Flow assessment, see Finding #2 in this report.

8) Assertion that the Event was unforeseen and unprecedented.

Taylor's Assertion:

"The MC 20 platform was toppled by a regional slope failure, an unforeseen and unprecedented underwater sea floor collapse and mudslide, during Hurricane Ivan…"

Task 8 & 9 Response:

Not only have there been multiple mud slides, slope seafloor collapse and hurricane events in the Gulf of Mexico resulting in damage to pipelines, oil & gas platforms and other infrastructure prior to this event, documentation exists showing that Taylor Energy was made aware of the seafloor stability risk at MC 20 site prior to the incident.

Chronology of Events and Documentation with respect to this issue

January 1984: SOHIO installed the MC20 A Platform

July 1991: BP acquired SOHIO and transferred title of the lease/platform

June 1994: Taylor Energy Company (TEC) acquired Lease No. G04935/Platform A from BP – including Lease Sell 66, Stipulation No. 4. Afterwards, TEC was responsible for the following platform modifications:

Lease Sale from BP to Taylor Energy Company – Taylor acknowledges and signs off on stipulation No. 4:

Portions of this lease may be subject to mass movement of sediments. Exploratory drilling operations, emplacement of structures (platforms), or seafloor wellheads for production or storage of oil or gas, and the emplacement of pipelines will not be allowed within the potentially unstable portions of this lease block unless or until the lessee has demonstrated to the Deputy Conservation Manager's (DCM's) satisfaction that the mass movement of sediments, is unlikely or that exploratory drilling operations, structures (platforms), casing, wellheads, and pipelines can be safely designed to protect the environment in case such mass movement occurs at the proposed location. This may necessitate that all exploration for and development of oil or gas be performed from locations outside of the area of unstable sediments, either within or outside of this lease block.

If exploratory drilling operations are allowed, site-specific surveys shall be conducted to determine the potential for unstable bottom conditions. If emplacement of structures (platforms) or seafloor wellheads for production or storage of oil or gas is allowed, all such unstable areas must be mapped. The DCM may also require soil testing before exploration and production operations are allowed.

Link to MC20 Lease Assignment from BP to TEC (reference Stipulation No. 4)
Link to Lease File OCS-G04935 (reference page 4, Stipulation No. 4)

[Simba] December 2003 – March 2004: Taylor Energy proposed the installation of Platform B (Simba) on their MC21 Lease (No. G15459; acquired in Sale 152 in 1995) through the CVA process, only 3 ½ miles to the east of MC20 Platform A, in 665 ft. of water

- Similar to MC20, the MC21 Platform B CVAs and applications noted that the seafloor at the location has the potential for "soil movement caused by severe waves" and cited surveying that addressed the risks of a "turbidity flow" or "slurry flow" occurring from storm conditions.
- **Since the prior surveyor opinion was that a severe "mud flow" only had a return interval of greater than 200 years, Taylor and their design firm chose not to include the catastrophic 200-year even in design criteria or structural analyses**.

[Simba] April 2004: MMS Approved Taylor's proposed installation of MC21 Platform B.
[Simba] June-July 2004: Taylor attempted to launch the MC21 Platform B jacket, but ran into problems with the barge.

September 2004: MC20 Platform A was toppled and slid ~600 ft downslope by hurricane-induced, **severe mud flow event**.

[Simba] December 2004 - January 2005: MC21 Platform B installation resumed/completed using the previous CVA-approved designs and fabrication (with no changes to the previously approved facility in response to the MC20 platform A toppling due to a sever mud flow).

September 2008: In response to USCG Admin Order No. 006-08 (to design/install a pollution containment system over the plumes in MC20), Taylor/Mr. Pecue informed the UC/USCG/MMS that out of concern for Lease 66 Stipulation No. 4, he should not install the containment equipment considering that future mud flow events could damage the pollution capture devices and cause an even greater environmental/ecological disaster than the continued sheening. In response, MMS prepared an Environmental Assessment (EA) in compliance with National Environmental Policy Act (NEPA) to address the Federal instructions to have Taylor stop the ongoing pollution.

Link to MC20 PCS SEA

APPENDIX A

ACRONYM AND ABBREVIATIONS LIST

bbls	barrels
BHP	bottom hole pressure
BML	below mudline
BSEE	Bureau of Safety and Environmental Enforcement
CFR	Code of Federal Regulations
EA	environmental assessment
FH	full hole
FISTE	Firms with Industry Specific Technical Experience
FMMG	Fugro-McClelland Marine Geosciences
FRACE	Final Risk Assessment and Cost Estimate
ft	feet
IW	intercept well
LLC	limited liability company
LWD	logging while drilling
MC	Mississippi Canyon
MMS	Mineral Management Service
NEPA	National Environmental Policy Act
Ppg	pounds per gallon
PSI	pounds per square inch
RFT	repeat formation tester
SCBD	Source Control Branch Director
SLB	Schlumberger
SME	Subject Matter Expert
SOSC	State On Scene Coordinator
SSC	Scientific Support Coordinator
TA	Temporary Abandonment
TEC	Taylor Energy Company LLC
USCG	United States Coast Guard