BSEE Panel Report 2019-002

Investigation of October 11, 2017 Flowline Jumper Failure

Lease OCS-G 24055
Mississippi Canyon Block 209
Gulf of Mexico Region,
New Orleans District

December 30, 2019

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List of Acronyms and Definitions

API RP	American Petroleum Institute Recommended Practice
BSEE	Bureau of Safety and Environmental Enforcement
CRO	Control Room Operator
DPT	Downstream Pressure Transmitter
GOMR	Gulf of Mexico Region
LACT	Lease Automatic Custody Transfer
LSH	Level Safety High
LSHL	Level Safety High/Low
MC	Mississippi Canyon
MPFM	Multi-Phase Flow Meter
OCSLA	Outer Continental Shelf Lands Act
OIM	Offshore Installation Manager
PIV	Production Isolation Valve
PLEM	Pipeline End Manifold
PLET	Pipeline End Termination
ROV	Remotely Operated Vehicle
SME	Subject Matter Expert

Figures & Illustrations

Executive Summary

Between the evening of October 11 and the morning of October 12, 2017, a fractured subsea wellhead jumper that connected the Mississippi Canyon (MC) 209 SS001 wellhead to a subsea manifold referred to as a PLET (Pipeline End Termination) released an estimated 16,000 barrels (bbls) of oil into the Gulf of Mexico (GOM).

The failed subsea wellhead jumper, designated as KAA-0120, Pipeline Segment Number 19174, operated at a water depth of 4917 feet within MC Block 209. The subsea well is part of the Neidermeyer Subsea System. The subsea well is tied into additional subsea lines flowing to the topside semi-submersible facility A (Delta House), located at MC Block 254, and operated by LLOG Exploration Offshore, LLC (LLOG).

LLOG shut in the Delta House platform on October 6, 2017, in preparation for the evacuation of personnel ahead of Hurricane Nate. Personnel returned on October 10. When ramp up for operations began that evening, operators observed the KAA-0120 flowline pressure measuring below hydrostatic pressure. This indicated to the operators that the flowline had integrity.

By the morning of October 11, Delta House Control Room Operators (CRO) began to observe that rates from the Multiphase Flow Meter (MPFM) installed on the KAA-0120 flowline did not match rates measured at the Lease Automatic Custody Transfer (LACT) meter. During the startup process, it is common for flow meter discrepancies to be noted for several hours until the well achieves a stabilized flow of fluids. The CROs also observed flow rate discrepancies at the top side separator meters. Delta House operators began to troubleshoot the meters both topside and subsea as a matter of course but did not suspect a loss of pipeline integrity.

A Level Safety High (LSH) indication from the Sump Tank shut-in the facility which interrupted the initial startup process. Operators subsequently reinitiated the startup process. Additionally operators on Delta House had to decrease oil export rates due to an issue at a downstream facility, Viosca Knoll (VK) Block 817 that receives oil from Delta House.

By the morning of October 12, operators at Delta House, after communicating with onshore LLOG personnel, concluded that all of the meters were working properly but still showed a discrepancy of approximately 5000 barrels. When the system achieved steady state flow, the operators compared various trend data to historical start-up trends and identified temperature and pressure drops. Concerns of a leak in the flowline began to escalate, and both the MC 209 SS001 and MC 208 SS001 wells were shut-in.

Delta House operators began to isolate the MC Block 209 SS001 well by remotely closing manifold valves. The subsequent observations indicated that the pressure at the flowline jumper or infield flowline was hydrostatic signifying a leak.

On October 12, LLOG conducted a visual inspection of the MC 209 flowline using a Remotely Operated Vehicle (ROV). The inspection confirmed that the jumper connecting the MC 209 SS001 wellhead to the PLET cracked at the base below the MPFM.

On October 13, BSEE Investigators photographed the sheen during a flyover on the way to initiate an onsite investigation (see Figure 1).

Ocean currents flowed to the South West at the time of the incident and away from the coast. No reports stated that oil attributed to the leak reached the shore.

Figure 1- Sheen observed during flyover.

Introduction

Pursuant to 43 U.S.C. § 1348(d)(1), (2) and (f) [Outer Continental Shelf Lands Act (OCSLA), as amended] and Department of the Interior regulations 30 CFR Part 250, requires the Bureau of Safety and Environmental Enforcement (BSEE) to investigate and prepare a public report of this incident.

BSEE convened a Panel comprised of BSEE Investigators and Engineers to conduct the investigation. The Panel members were:

Stephen Harris, Petroleum Engineer/ Investigator, Office of Incident Investigations, GOMR
Michael Idziorek[1], Special Investigator, Safety and Incident Investigations Division, HQ
Anthony Pizza, Petroleum Engineer, Production Operations Section Chief, New Orleans District
Phillip Smith, Pipeline Engineer, Regional Pipeline Section, GOMR
Gerald Taylor, Accident Investigator, New Orleans District

The purpose of this investigation was to identify and document the cause or causes of the incident. The report includes the conclusions made by the panel. Recommendations that may reduce the likelihood of a recurrence or similar incident in the future are also included.

Lease Location & Information

Figure 2- Incident Location

The incident occurred in MC Block 209, Outer Continental Shelf (OCS) lease G24055. The lease covers approximately 5,760 acres on the OCS, within the GOM, approximately 53 miles South East from the Louisiana coast (see Figure 2). Dominion Exploration & Production, Inc. and Spinnaker Exploration Company, L.L.C. purchased the lease, each at fifty percent interest, effective August 1, 2002, in lease sale number 182.

Ownership interests changed over time, and as of the date of the incident the lease had multiple entities with ownership interest: LLOG Bluewater Holdings, L.L.C. (51.78075%); Calypso Exploration, LLC (10.125%); Ridgewood Energy Bluewater Oil Fund III, LLC (3.26778%);

[1] Panel Chair

Crux1, LLC (16.15625%); Ridgewood Energy Gulf of Mexico Oil and Gas Fund, L.P. (2.13335%); Red Willow Offshore, LLC (10.125%); ILX Prospect Neidermeyer, LLC (5.40113%); and LLOG Exploration Offshore, L.L.C. (1.01074%).

As of October 16, 2014, each of the ownership entities designated LLOG as operator for all of MC Block 209. As the designated operator and agent, LLOG had full authority to act on the lessee's/operating rights owner's behalf, to fulfill the lessee's/operating rights owner's obligations under the OCS Lands Act, in compliance with the terms and conditions of the lease, laws and applicable regulations.

Explanation of Process Flow

Normal flow from the MC Block 209 SS001 well began at the wellhead and flowed through a well jumper with a MPFM installed in line with the jumper. This jumper connected to a PLET. A flowline from the PLET then connected to a Pipeline End Manifold (PLEM). A second jumper then connects to the MC Block 253 subsea manifold. From this manifold, flow continued through either the north or south flowline to Delta House. The fracture occurred at the wellhead jumper, as shown in Figure 3.

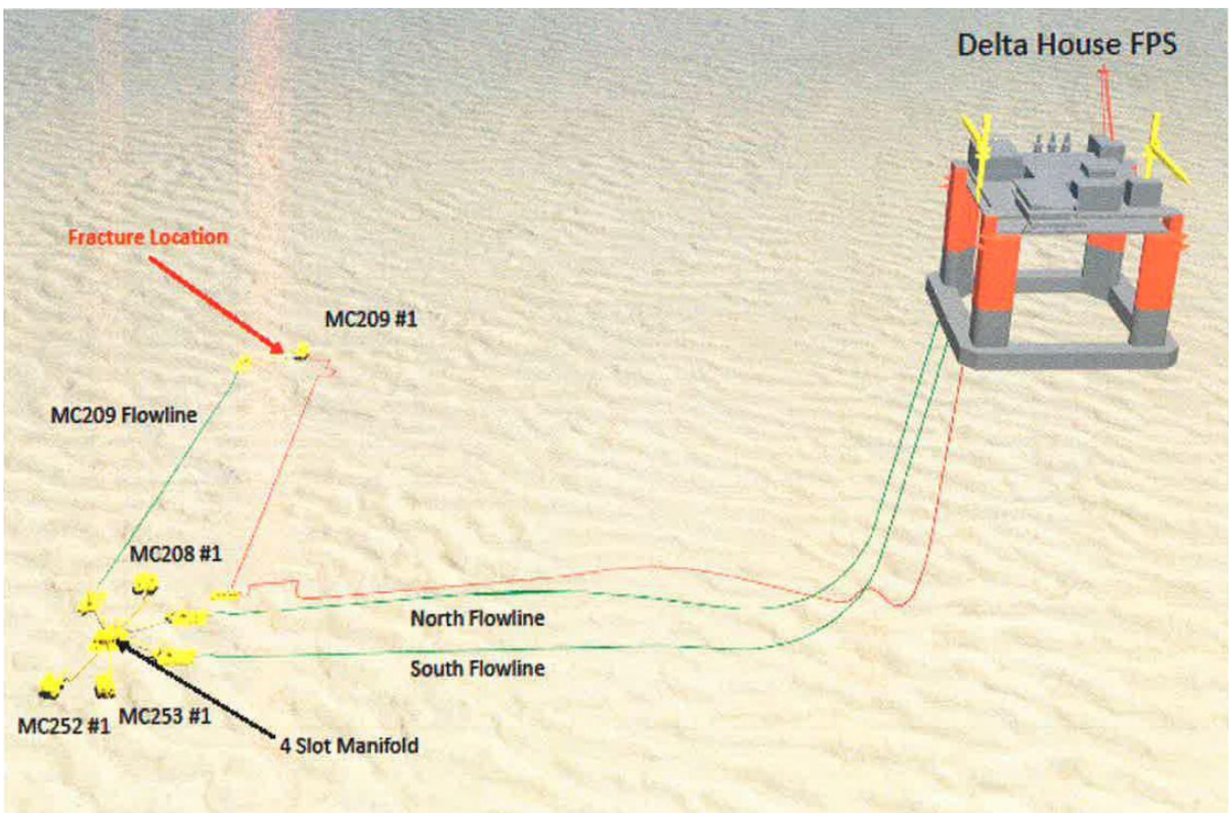

Figure 3- Neidermeyer Subsea Field Overview (LLOG)

Incident Timeline

On October 6, 2017, LLOG evacuated the Delta House platform in preparation for Hurricane Nate. Workers returned to the platform and began the process of powering up the facility on October 10.

On the morning of October 11, during ramp-up of production fluid flow, operators began to observe that flow rates measured by the MPFM located at the MC 209 SS001 well did not match the rates measured by the Lease Automatic Custody Transfer (LACT) meter located on Delta House.

By the evening of October 11, operators continued to measure discrepancies in the flow rates. The operators began troubleshooting to determine if the MPFM had measuring errors.

This included remote analysis of trend data by LLOG engineers from their headquarters in Covington, Louisiana.

During this troubleshooting and verification of the meter discrepancy, a Level Safety High Low (LSHL) tripped at the Delta House Sump Tank. Although unrelated to the flow from the wells, this triggered a facility shut-in.

Analysis of the trend data available up to the shut in led LLOG engineers to believe that the flow rate discrepancies resulted from an issue with the platform meters and that they should be examined.

Approximately an hour after the LSHL shut in, Delta House operators re-started the ramp up process.

By the morning of October 12, the Offshore Installation Manager (OIM) from Delta House notified LLOG engineers that Delta House personnel investigated and verified that the platform meters are measuring flow rates correctly. LLOG personnel compared historical pressure and temperature data trends to trend observed during the current startup. This information, along with confirmation that the meters were reading correctly, led the OIM to be concerned that there was a fracture somewhere in the flowline. LLOG engineers directed the OIM to shut-in the wells and requested a helicopter to fly the path of the subsea pipeline from Delta House to the location of the MC 209 SS001 well.

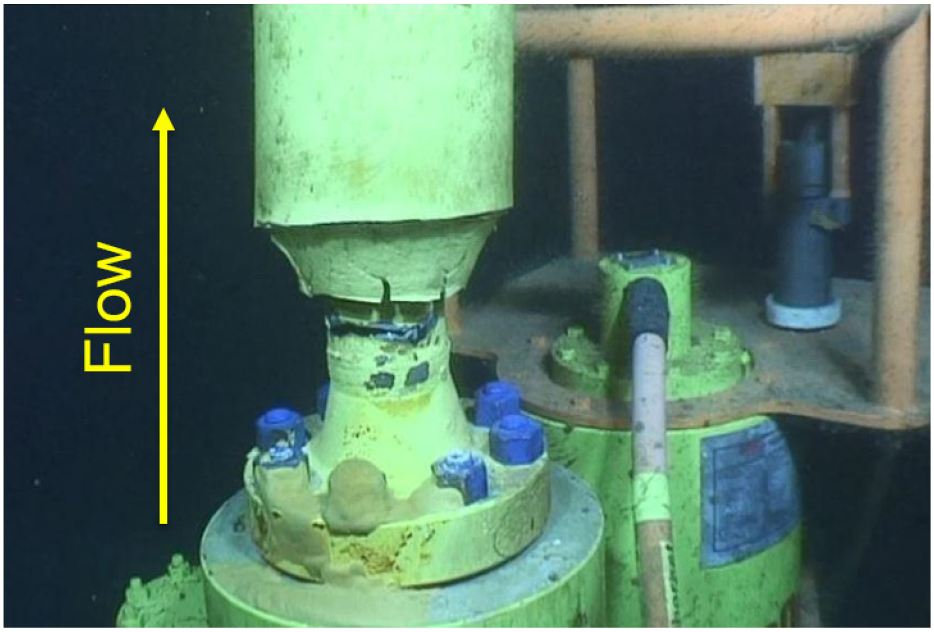

Figure 4- Crack downstream of MPFM flange

Personnel conducting the flyover observed three separate sheens on the water's surface. Subsequently, LLOG conducted an underwater survey using a ROV. LLOG engineers visually confirmed that the MC 209 SS001 jumper connecting the wellhead and the PLET fractured immediately after the downstream MPFM flange (see Figure 4).

BSEE Investigation & Findings

During its investigation the BSEE panel conducted interviews of LLOG engineers and operators working on Delta House at the time of the incident. The BSEE panel witnessed the recovery of the MC 209 jumper, and panel members were present when testing occurred on the jumper. The BSEE panel made a number of document requests to LLOG and reviewed the responsive material.

PLET and Pipeline Construction and Movement

LLOG completed the MC 209 PLETs, jumper, and flowline installation as approved on April 17, 2015. During the ROV inspection conducted on October 12, 2017, it appeared that PLET connected to the wellhead by the fractured jumper moved from its installed position (see Figure 5).

LLOG concluded this movement resulted from thermal walking of the pipeline. Thermal walking occurs when a pipeline heats and expands as oil from the reservoir flows through the pipeline. This expansion placed force on the PLET and caused the PLET to move outside of its design location. This movement exerted excess stress on the well jumper and is a contributing factor to the jumper failure.

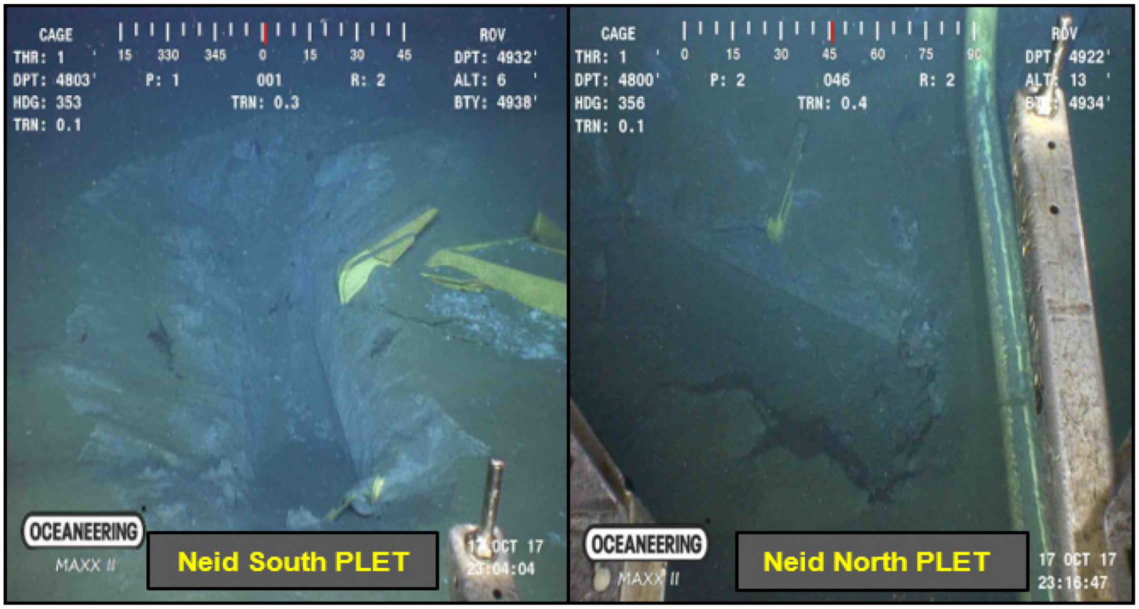

Figure 5- ROV footage with seafloor disturbance from PLET movement.

Meters

The subsea MPFM used on the MC 209 well measures flow rate with two independent sets of sensors, named A Side and B Side, which communicate with the topside controls. Each side is connected to its own Subsea Electrical Module (SEM) for redundancy; if one side fails, the flow rate can still be measured by the other. The A Side and B Side sensors are identical, except that the A Side also uses Electrical Capacitance Tomography (ECT) technology to determine the volume of each fluid phase for a more accurate measurement. Because the A Side is more accurate, LLOG operated the MPFM using the A Side as the primary sensor set.

As fluid flows through the jumper, the meter sensors collect temperature, pressure, differential pressure, and bulk density data. The raw data is then used to calculate a shrinkage factor[2] by correlating the variables to pressure-volume-temperature (PVT) tables created from well tests. The shrinkage factor is used to convert the subsea volumetric flow rates of each phase of the fluid to equivalent volumetric flow rates at the surface (standard temperature and pressure).

Both A and B Sides of the MPFM rely on the PVT tables to calculate flow rates. The MPFM requires that the PVT tables be manually updated for each sensor set. As the reservoir is depleted, the PVT table information changes, and the meter logic must be periodically updated with new PVT table information to ensure the accuracy. LLOG operators stated that they did not always update each side at the same time, and since the A Side was the primary sensor set, it had the most up-to-date PVT tables. This increased the inaccuracy of the B Side compared to the A Side.

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[2] The formation volume factor is the ratio of the volume of oil at pressure and temperature to the volume of oil at standard conditions.

At the time of the incident, the pressure transmitter on the A Side of the meter failed and the operators decided to use the pressure that occurs during steady flow and input it as a fixed number into the A Side logic. Therefore, instead of the flowrate calculation using the actual flowline pressure, it used the fixed number that the personnel input. This caused the flow rate during startup to be inaccurate because the actual flowing pressure was less than that of the pressure used to calculate flow rate.

The operators knew of the inaccuracies of both A and B Sides of the meter during startup, which led them to assume the MPFM needed to be calibrated instead of there being a leak.

The operators compared data from meters on the facility located at the separators against MFPM data. The facility had previous calibration issues when the surface meters incorrectly reset after a loss of power. Since personnel just returned after an evacuation due to a hurricane; the surface meters lost power. When the MPFM did not show calibration issues, the operators concluded that the surface meters incorrectly reset and needed to be recalibrated.

Internal Corrosion

Upon its recovery, LLOG sent the fractured portion of the jumper piping to shore for analysis. LLOG contracted the testing party with BSEE panel members being present during testing.

The piping section was constructed of API 5L Grade X65 steel. Visual observations revealed evidence of corrosion on the inside surface of the piping. The pipe suffered a wall thickness loss of nearly 50% relative to what would be nominal thickness of the steel. The fracture area had the highest thickness loss. (Figure 6)

(1) 0.207”
(2) 0.208”
(3) 0.229”
(4) 0.191”
(5) 0.164”
(6) 0.184”
(7) 0.138”
(8) 0.220”
(9) 0.189”
(10) 0.152”
(11) 0.167”
(12) 0.180”
(13) 0.215”

Figure 6- Jumper cross section showing wall thickness loss.

The corrosion pattern had a distinctive plateau and pitting pattern (Figure 7). Analysis concluded that carbonic acid corrosion was the primary mechanism responsible for the metal thickness loss. Carbonic acid occurs when carbon dioxide dissolves in water and is aggressive to steel.

Figure 7- Pitting on inside of jumper

The concentration of corrosion in areas of the piping which were downstream of fittings and 90-degree bends in the jumper was evidence that the corrosion occurred during service. The fittings and 90-degree bends increase turbulence in the fluid flow. This turbulence increases the likelihood of corrosion by shifting the fluid flow from oil wet[3] to water wet[4], and it can work to remove any corrosion protective layers by erosion.

Hydrate Formation During Completion

After completion, the MC 209 well required hydrate remediation, and spent completion fluid possibly remained in the jumper without being fully cleaned out.

When LLOG installed the jumper connecting the wellhead to the PLET it was full of seawater. To displace this seawater and try to mitigate hydrate formation, the installation company pumped methanol into the flowline before opening the well. After LLOG opened the well, the remaining spent completion fluid and formation fluid likely mixed with the methanol, but before the

[3] *Oil wet* refers to the preference in a multiphase flow of a solid to be in contact with the oil phase of production fluids as opposed to other phases.
[4] *Water wet* refers to the preference in a multiphase flow of a solid to be in contact with the water phase of production fluids as opposed to other phases.

mixture of fluids flowed out of the line, a hydrate plug formed, requiring that the well was shut in.

With the well shut in for a month while LLOG remediated the hydrate plug, the combination of spent completion fluid, reservoir fluid, and methanol can create an acidic environment that began the corrosion process of the jumper's inner surface. Though this corrosion might not be severe, it can exacerbate the carbonic acid corrosion that occurred during production conditions.

Leak Detection

LLOG did not identify the MC-209 leak for over 24 hours. To understand the challenges of subsea leak detection, the BSEE investigation team examined the traditional leak detection methods and analyzed the pressure trends of several well start-ups. Despite having advanced MPFM technology, BSEE found LLOG's overall leak detection ability inadequate at identifying major subsea leaks.

Typical leaks release hydrocarbons to atmospheric pressure. Low pressure is the detectable abnormal condition which indicates a leak occurred. American Petroleum Institute (API) Recommended Practices (RP) 14C, incorporated by reference in 30 CFR 250.198, states that the "primary protection from leaks of sufficient rate to create an abnormal operating condition within a pressure component should be provided by a PSL sensor to shut off inflow." However, subsea leaks interact with hydrostatic conditions, not atmospheric. In the case of the MC 209 leak, the hydrostatic pressure was close to 2000 psi. During start-up conditions, the flowline often measured in the range of 2000 psi which is below hydrostatic pressure. Therefore, no appropriate PSL set point can accurately detect leaks.

At the time of the leak, regulations or recommended practice did not require advanced subsea leak detection, nor had any technology been widely available for use in the GOM. With the ineffective PSL, subsea leak detection heavily relied on experienced Subsea Operators to identify abnormalities in flowline pressure and temperature trends that would indicate a leak or other undesirable event.

After reviewing trend data of the subsea pressures, BSEE Subject Matter Experts (SME) determined that the complexity of operations made it difficult for operators to identify leaks in a positive manner. At the time of this leak, the well was in a transient state. A transient state exists when the flowline pressures and temperatures are not stable. These conditions routinely occur during well start-up and shutdown. Well start-ups, in particular, cause large pressure fluctuations that look similar to leaks. Although subsea leaks are characterized by a pressure that trends toward subsea hydrostatic pressure, the following well start up activities can drive similar trends:

- Subsea choke operation: The subsea choke starts in a closed position prior to start-up. It then opens deliberately to control the pressures and flow from the well to the downstream flowline equipment.

- Topside choke operation: This choke controls the pressure and flow from the flowline to the topsides equipment.
- Slugging: In vertical flow, slugging is a multiphase fluid flow characterized by a series of liquid slugs separated by gas pockets. The resulting flow alternates between high liquid and high gas compositions which causes substantial fluctuations in pressure.
  Other Subsea Wells start-ups: Change of state in other subsea wells that are in communication with the manifold cause pressure fluctuations.

In Figure 8, the Downstream Pressure Transmitter (DPT) is located downstream of the Pressure Control Valve (PCV), which is commonly referred to as the subsea choke. The subsequent trend (Figure 9) provided in this report refers to DPT pressure as either "Flowline Pressure" or "MC 209 1: DOWNSTREAM PRESSURE." The location of the leak is immediately downstream of the MPFM flange shown on the right side of the drawing. When the Production Isolation Valve (PIV) is in the open position, the DPT has an accurate reading of the flowline pressure at the location of the leak.

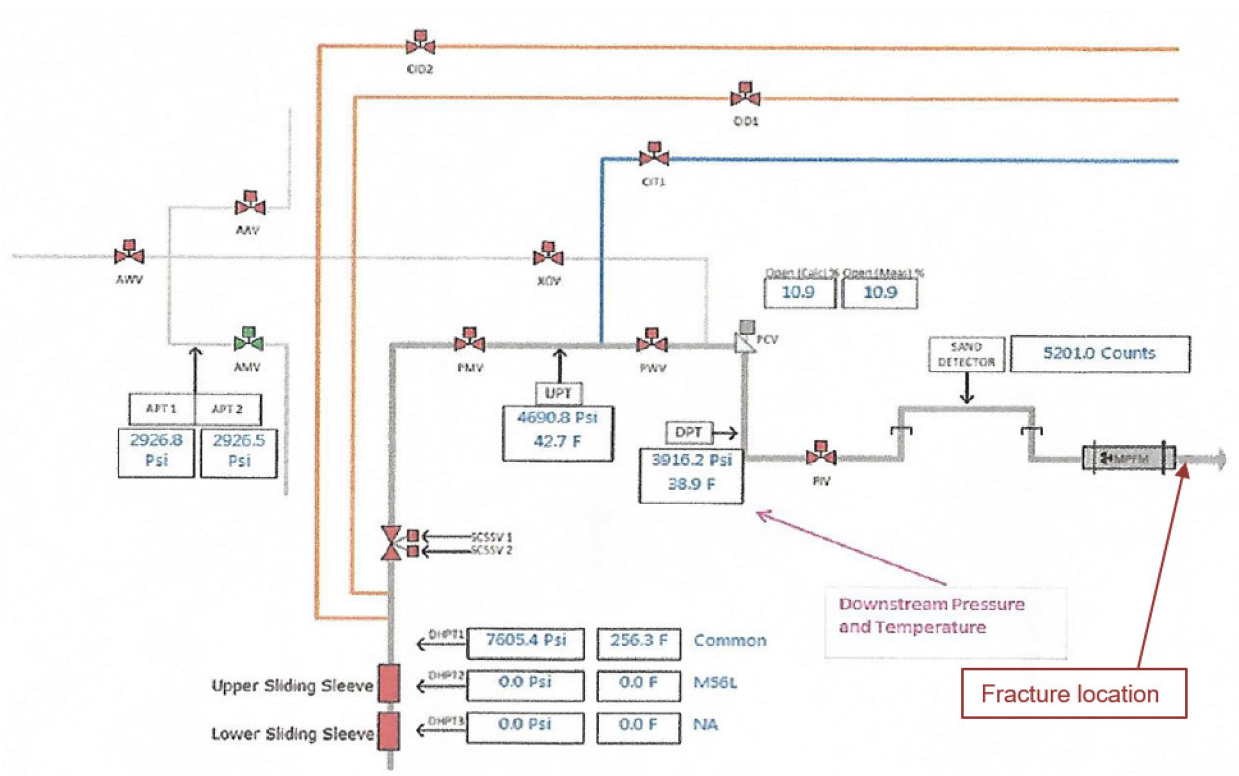

Figure 8 - MC 209 flow schematic.

Analysis of this DPT trend (figure 9), shown in red, indicates loss of flowline integrity occurred on October 11, 2017, at 00:42. The loss of flowline integrity is characterized by the jumper pressure trending toward the hydrostatic pressure. However, the pressure of the well while flowing prevents the jumper pressure from reaching hydrostatic pressure.

At 20:46 on October 11, 2017, the jumper pressure increased to 5000 psi as the PIV (yellow) closed due to a platform shut-in. When the PIV opened again, the jumper pressure immediately dropped to hydrostatic pressure. This is a possible indication of a leak but is inconclusive. It is not abnormal for a flow line's settle-out pressure to equal external seawater hydrostatic pressure when the well's operating pressure is relatively close to hydrostatic pressure.

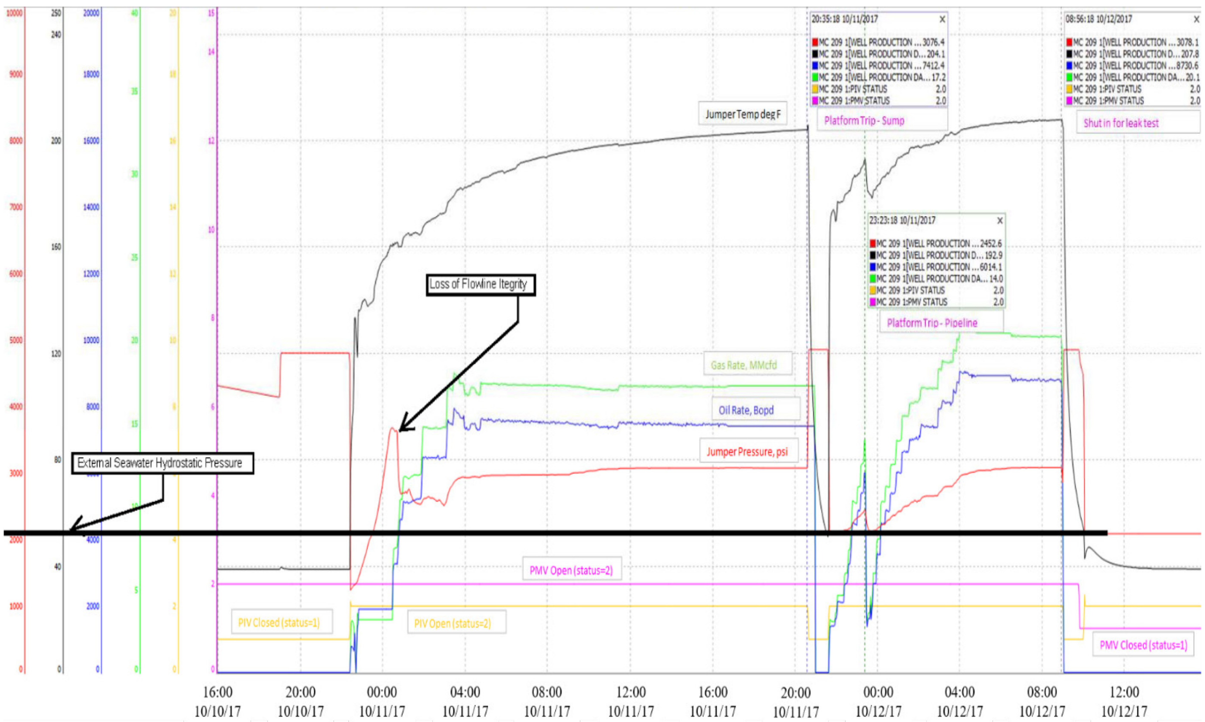

Figure 9- MC 209 well start up trend for 10/11/18.

Next, at 08:50 on October 12, 2017, LLOG shut-in the well, and the jumper pressure increased again to the well's shut-in pressure. LLOG then conducted a series of isolation leak tests to identify the general location of the leak. The drop in pressure shown around 10:00 shows the flowline pressure rapidly trending toward hydrostatic pressure. This gave LLOG positive identification of a leak.

Although LLOG's Control Room Operators and Engineers were experienced with well start-up, more comprehensive training specific to subsea leak detection may have allowed the personnel to identify the leak on October 11, 2017, at 00:42 as the jumper pressure trended toward hydrostatic pressure.

For context, a comparison to the trend seen at the time of the incident Figure 10 is included in Appendix A. The reason for this comparison is to highlight the complexity of well start up. Looking only at the pressure of the flowline does not give a reliable indication of a leak. Other factors, such as choke operations and slugging, must be considered when analyzing trends for leaks.

The MC-209 well start-up trend for March, 2016, shows the behavior of subsea manifold pressure during well start up (Fig. 11). For the first several hours of start up the flowline experiences erratic pressure swings. However, the operation of the subsea choke directly corresponds to the to pressure changes. This comparison trend exemplifies that the choke can cause pressure changes that mimic a leak.

The CROs first indication of an abnormality was through the discrepancy between the Subsea MPFM and the topside LACT meters, not analysis of pressure trends. Interviews with LLOG engineers revealed that it was common for the MPFM to have discrepancies that could be fixed with recalibration. Furthermore, there were no alarms or procedures that directly tied the MPFM discrepancies to leaks.

During interviews, LLOG revealed that they did not train CROs to actively consider a leak as an explanation when unexpected pressure fluctuations occur, or to have CROs shut in a well while anomalous trends are analyzed.

Conclusion

The BSEE panel concluded that the loss of an estimated 16,000 bbls of oil into the GOM from subsea infrastructure going undetected over several hours resulted from a failed jumper that connected the wellhead to the PLET.

This failure resulted from internal corrosion within the jumper and mechanical stress added to the jumper from movement of the PLET and pipeline.

The panel also evaluated why platform CROs and LLOG Engineers did not detect the leak sooner and shut in the well. LLOG did not have any sensors in place that would alarm due to a suspected subsea leak[5]. LLOG relied heavily on the experience level of their CROs. The CROs, although experienced, were not trained to shut in wells for unexplained pressure fluctuations or metering discrepancies.

Based on interviews conducted during the investigation, the panel learned that LLOG CROs and engineers had a prevalent mindset that meters are prone to malfunction or meter calibration issues cause discrepancies in flow rate measurement. Further, there was a common belief that subsea flow lines rarely fail. The result being that no consideration was made that a leak was occurring for several hours into the well start up.

[5] LLOG did have a PSL installed, but the set point was below hydrostatic pressure.

Recommendations

Efforts to improve subsea leak detection by both BSEE and industry began within two weeks of the MC209 incident. In accordance with a request from the BSEE Gulf of Mexico Region Director, the Offshore Operators Committee (OOC), a representative organization for the offshore oil and gas industry operating in the Gulf of Mexico OCS, approved the formation of a subsea leak detection work group on October 19, 2017. The first subsea leak detection work group meeting occurred on November 1, 2017, and BSEE met with the work group on November 6, 2017 to discuss concerns about the lack of effective subsea leak detection strategies.

The OOC work group held two industry workshops to address potential improvements to subsea leak detection processes. The first took place on July 17, 2018 in Covington, Louisiana and the second on November 1, 2018 in New Orleans. In early 2019, BSEE began calling offshore operators individually requesting updates about subsea leak detection improvement plans. During these one-on-one meetings, all OOC member operators committed to implementing improved subsea leak detection strategies by the end of 2019. These efforts are detailed in a July 2019 report[6] which the investigation panel had access to and was able to review prior to completing their investigation.

The panel agrees with and recommends that collaborative efforts to improve overall subsea leak detection should continue. Additionally, the panel makes the following recommendations, which are the result of the conclusions reached in this investigation:

Recommendations to LLOG and Industry

The BSEE panel recommends that operators increase scrutiny in the design, placement, and maintenance of their subsea infrastructure and focus on:

Flowline construction:

- Evaluate designs of applicable components for their tolerance under increased loads due to thermal expansion or other movement.
- Evaluate the use and placement of sleepers or other components that mitigate the buckling of pipelines.
- Evaluate the construction of flowline components to ensure that materials have adequate corrosion mitigation properties.
- Evaluate the use of different surveying methods such as Light Detection and Ranging (LIDAR) to confirm that pipeline systems remain within their design tolerances throughout their service life.

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[6] BSEE Report, "A New Era of Management: Diving Safety Performance and Environmental Stewardship Improvements Beyond Regulation through Innovation and Collaboration: Subsea Leak Detection, July 2019"

Leak detection:

- Consider revisions to API RP 17V that include a section on subsea leak detection best practices.
- Consider improving subsea leak detection methods by employing conditional rate of change, mass in mass out, or other advanced monitoring technologies. These technologies should alarm, and where possible, initiate executive actions.
- Control room operators should receive training that increases the awareness of the possibility of flowline integrity loss to a higher consideration when undergoing startup operations.
- Due to its complex nature, pressure trend analysis for leak detection training should be evaluated and where possible enhanced.

Appendix A

Figure 10- MC 209 comparison startup trend from 3/24/16.