National Transportation Safety Board

Office of Railroad, Pipeline and Hazardous Materials

Washington, DC 20594

PLD-24-FR-001

HUMAN PERFORMANCE, SYSTEM SAFETY AND SCADA

Group Chair's Factual Report

September 28, 2024

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A. ACCIDENT

Location:	Gulf of Mexico, Louisiana
Date:	November 15, 2023
Time (approx.):	7:00 PM (local) 1:00 AM (UTC)
Operator:	Third Coast Infrastructure LLC (Third Coast)
Pipeline:	Main Pass Oil Gathering System (MPOG)
System Type:	Offshore transmission system
Commodity:	Crude oil

B. HUMAN PERFORMANCE AND SYSTEM SAFETY GROUP

Group Chair	Stephen M. Jenner, Ph.D. Human Performance and System Safety Investigator National Transportation Safety Board Washington, DC
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C. SUMMARY

On November 15, 2023, about 7:00 p.m. local time, pipeline control room operators observed a pressure drop in an underwater crude oil pipeline owned by Third Coast Infrastructure LLC (Third Coast) and located within Main Pass 69 in the Gulf of Mexico.[1] On November 16, 2023, shortly after the start of the 6:00 a.m. shift, control room personnel – after reviewing and discussing the events of the previous shift with other personnel – took action to shut down and isolate the pipeline. By this time, a leak released approximately 27,000 barrels of crude oil into an area about 20 miles southeast of Venice, Louisiana.[2] Third Coast reported a leak of unknown volume to the National Response Center at 9:51 a.m. CT on November 16, 2023. No injuries were reported, and the crude oil did not ignite. On November 17, the US Coast Guard Command Center reported that crude oil was released by Third Coast in the Main Pass area close to Plaquemines Parish, southeast of New Orleans, Louisiana.

The U.S. Coast Guard, the Louisiana Oil Spill Coordinator's Office, and MPOG established the Unified Command on November 17, 2023, to direct the response to the crude oil release. Remotely operated vehicles and divers inspected the pipeline and on December 21 found indications of oil in the seabed above the pipeline. The investigation determined that the leak occurred in an 18-inch diameter steel pipe operated by Main Pass Oil Gathering Company LLC (MPOG), a wholly owned subsidiary of Third Coast.

Parties to the investigation include the U.S. Coast Guard; the Pipeline and Hazardous Materials Safety Administration; the Bureau of Safety and Environmental Enforcement; Third Coast; and Oil States Industries.

[1] (a) All times in this report are local times. (b) Main Pass 69 indicates where in the Gulf of Mexico the section of pipe was located.

[2] *Title 49 Code of Federal Regulations* Part 195.6 defines an *unusually sensitive area* as a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

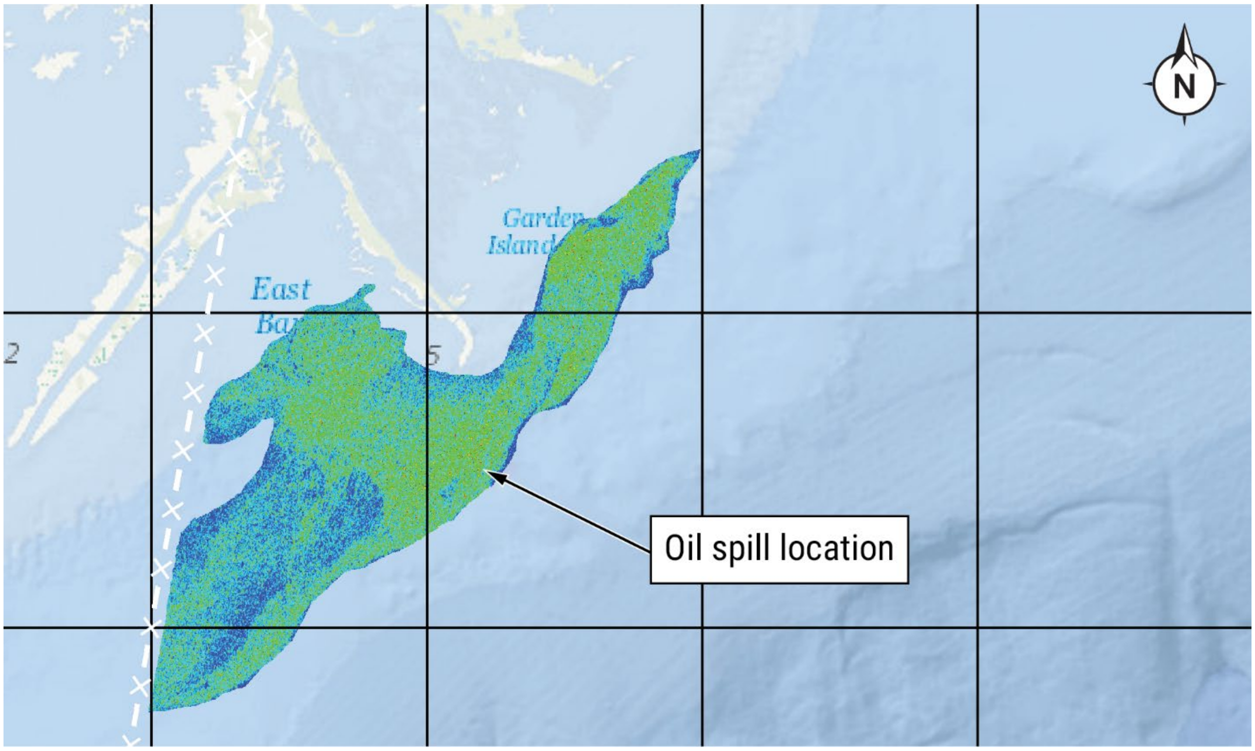

Figure 1. *Map of the oil spill location about 20 miles southeast of Venice, Louisiana, within Main Pass 69 in the Gulf of Mexico. (Source: NOAA.gov.)*

D. DESCRIPTION OF THE OPERATOR

Third Coast Infrastructure, LLC ("Third Coast") is headquartered in Houston, Texas. Third Coast is an offshore focused midstream company whose operations are situated along the Gulf Coast and in the Gulf of Mexico.[3] Third Coast is the parent company to or operator for multiple entities, including but not limited to American Panther, LLC ("Panther"), Lighthouse Midstream Services, LLC ("Lighthouse"), and Main Pass Oil Gathering, LLC ("MPOG").[4,5] The company's assets include offshore crude oil and natural gas liquids pipelines, a deepwater floating production system, natural gas gathering and transmission pipelines, and gas processing plants.[6]

[3] https://www.third-coast.com/about-us
[4] https://www.third-coast.com/_files/ugd/d12b1c_6e7ed9f9b6bc4eb7b1d445da268ec0be.pdf
[5] Third Coast owns MPOG.
[6] https://www.third-coast.com/about-us

E. DESCRIPTION OF THE PIPELINE SYSTEMS

The MPOG pipeline system consists of an 18-inch Panther pipeline that originates in the Gulf of Mexico Main Pass 225 (“MP225”) lease block and extends to the MP-69A station located in the Main Pass 69 (“MP69”) lease block, which is owned by Crescent (*Figure* 2).[7,8] There are at total of six pipeline connection points where crude oil is introduced into the MPOG pipeline system. These pipeline connection points include a topside pumping station located in the MP225 lease block and five subsea pipelines including pipeline segment number (PSN) 11928 in the Main Pass 245 (“MP245”) lease block, PSN 20793 in the Main Pass 268 (“MP268”) lease block, PSN 19762 in the Main Pass 273 (“MP273”) lease block, PSN 19899 in the Main Pass 144 (“MP144”) lease block, and PSN 19371 also in the MP144 lease block (*Figure* 3). A total of seven assets feed into these six pipeline connection points, as shown in *Table* 1.[9] Once the crude oil in the MPOG pipeline system is received at the MP69 station, ownership transfers from Third Coast to Crescent.[10]

[7] Official Protraction Diagrams (OPDs) And Leasing Maps (LMs) & Supplemental Official OCS Block Diagrams (SOBDs) | Bureau of Ocean Energy Management (boem.gov)
[8] Crescent’s MP 69 “A” station receives crude oil from the Third Coast MPOG pipeline system, as well as from their own Pompano, Delta & Delta North pipelines. (RE: MP 69 metering information-MPOG release November 15-16, 2023 (email response))
[9] MPOG LACT Meter Data - 2023-11-15 through 11-16_1000
[10] Crescent only delivers crude oil to Shell at the MP 69 “A” station. (RE: MP 69 metering information-MPOG release November 15-16, 2023 (email response))

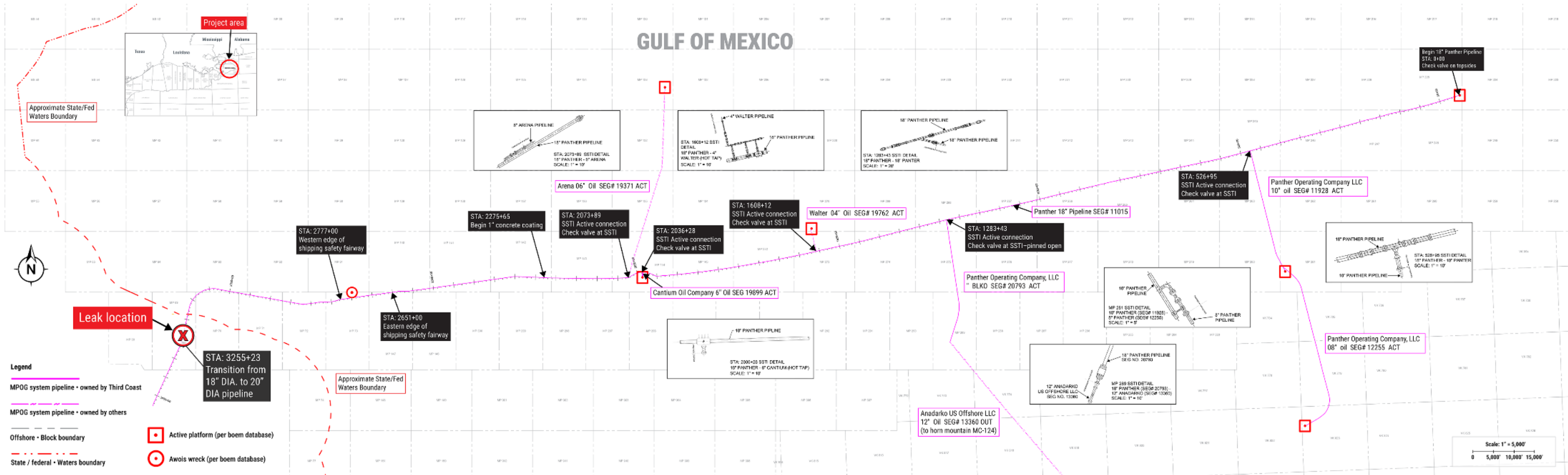

Figure 2. *Simplified map showing MPOG Pipeline System*

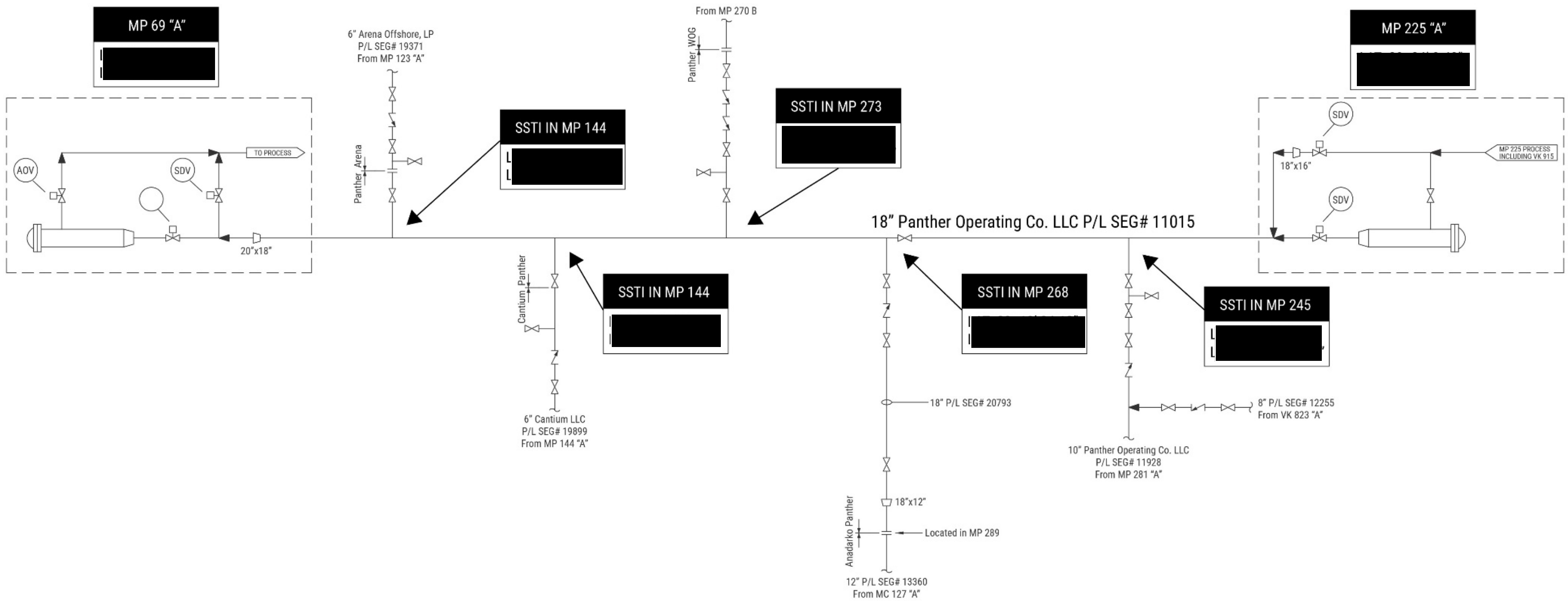

Figure 3. *Simplified process flow diagram showing pipeline connections to MPOG Pipeline System*

Table 1. List of assets that connect to MPOG Pipeline System

Asset Name	Lease Block	Connection to MPOG Pipeline	Pipeline Diameter	Operator Name
MP-123A	MP 123	PSN 19371	6-inch	Arena Offshore, LP
MP-144A	MP 144	PSN 19899	6-inch	Cantium, LLC
MP-270B	MP 270	PSN 19762	4-inch	Walter Oil & Gas Corporation
MC-127A (Horn Mountain)	MC 127	PSN 20793	18-inch	Occidental Petroleum Corporation ("OXY")
MP-281A	MP 281	PSN 11928	10-inch	Talos Energy Ventures, LLC
VK-823A	VK 823	PSN 12255 *(ties into PSN 11928)*	8-inch	W&T Energy VI, LLC
VK-915A (Marlin)	VK 915	PSN 11765	18-inch	Occidental Petroleum Corporation ("OXY")

F. CONTROL ROOM INFORMATION

The Third Coast control room located in Houston, Texas is the central location for monitoring and controlling pipeline operations. The control room is owned and operated by Third Coast and is staffed 24 hours per day, 365 days a year by two pipeline controllers. Additionally, during the morning/day shift on Monday – Friday, the control room is also staffed with two Shift Leads. The control room consists of four working consoles. Consoles 1 and 2, commonly referred to as OCC1 and OCC2, respectively, are operated by pipeline controllers. Consoles 3 and 4 are operated by shift leads but mimic OCC1 and OCC2 in configuration. OCC2 has a total of 18 monitors dedicated to Supervisory Control and Data Acquisition (SCADA) and two additional monitors dedicated to IT systems. OCC2 monitors both liquid and natural gas pipelines, including the MPOG pipeline system, Ozark Pipeline, Mississippi Pipeline, Great Salt Plains Midstream Pipeline, KPC Pipeline, Echo Canyon Pipeline, and Caddo Pipeline.[11]

G. OPERATIONS CONTROL CENTER EVENTS TIMELINE (NOVEMBER 15-16, 2023)

The following timeline was developed from information included in the LMS OCC Daily Log Entry, interviews of Third Coast employees during the on-scene investigation; written statements by the pipeline controller; NTSB-led interviews of the field technician (via Teams); the pipeline controller's termination meeting notes on November 16, 2023; and data from the SCADA system.

[11] MPOG-010692-MPOG-010692 - Pipelines Operated on OCC Console 2

The Third Coast pipeline controller for OCC2 began his shift at 6:00 p.m. on the evening of November 15, 2023, at which time he was responsible for monitoring the SCADA data for the MPOG pipeline system, and several other pipeline systems.[12]

About 6:00 p.m., the SCADA data shows a pressure increase at MP69 on the MPOG system. About 6:33 p.m., the data shows the first indication of a pressure decrease. The pipeline controller first noticed the changes in pressure around 6:45 p.m. He told investigators this was common on an active pipeline, and explained that pressure trends at 7:00 p.m. indicated a normal drop in pressure.

At 6:33 p.m., the pipeline controller entered in the Daily Logger (a calculation based on the accumulation receipts and accumulation deliveries) an imbalance of -174 barrels.[13] (Four hours earlier, around 2:38 p.m., the imbalance was one barrel). SCADA data indicated that at 7:30 p.m. the cumulative net barrels was 132 bbls, and starting to increase). The pipeline controller recalled that around 7:30 p.m. he observed that on the MPOG system the deliveries difference was 600 bbls.[14] The pipeline controller then started analyzing SCADA data for possible trends. At this time there was flow through meter run 1 & 2 at delivery station (MP69).

The pipeline controller told investigators that flow imbalance could exist for many different reasons, but most often due to station communications outages. He said that another reason may be that the pipeline is pressuring or de-pressuring.

The Third Coast pipeline controller lead (who was not on duty the night of November 15, and went on duty November 16 at 6:00 a.m.) told investigators that there are many ways to identify a possible leak on a pipeline; and that accumulation, flow rate and pressure need to be investigated. He stated that there were no alarms

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[12] In this report, the Third Coast pipeline controller for OCC2 will be referred to as the pipeline controller.

[13] Pipeline controllers are instructed to manually enter the imbalance values every four hours at 0230, 0630, 1030, 1430, 1830, and 2230. The pipeline controller entered the imbalance only one time, at 6:30 p.m., because he was "heavily occupied talking to field technicians, my supervisor and troubleshooting." The controller also discussed responding to alarms and answering calls on other systems during his shift.

[14] The controller's detection of an imbalance of 600 bbls would have occurred after 7:30 p.m. SCADA data, shown in Table 3, indicated that at 7:30 p.m. the imbalance was 132 bbls and trending higher. Consequently, an imbalance of 600 bbls would have occurred after 7:30 p.m. and before 8:30 p.m. (when the imbalance was 1101.00 bbls).

triggered or activated for pressure, flow rates or accumulations for this event.[15] He further stated that there was no set number of barrels discrepancy that required further investigation. He said that for him, an imbalance greater than 100 barrels would initiate an investigation for that potential issue. He was not aware of any policy or procedure indicating that when the imbalance gets to a certain amount the system should be shut down.[16]

At 7:37 p.m., the first of a long series of low-pressure alarms ("Low Limit Exceeded [300]") at MP69 appeared on the SCADA system. The pressure "Returned to normal from Low" about 28 seconds later. At 8:10 p.m. the pipeline controller started looking at pressure and flow rate trends from different platforms.[17] At 8:20 p.m., he considered the meter at MP69 might not be reading correct flow rate. To verify that the meter's readings were not the issue, he closed one of the meter runs at MP69 and opened a different meter run to see if the flowing rate would change or was any different. The pipeline controller saw no difference; that is, he saw the same flow rate as the previous two meter runs. He also noticed that the difference between the receipt and the delivered barrels was continuing to increase.

At 8:50 p.m. the Third Coast pipeline controller called another control room (a third party control room called Everline) that was responsible for receiving the delivery of flow after the MPOG meters at MP69. This call to Everline control room was to verify that the meters at MP69 flow values were similar, confirming that the meter flow rate at MP69 was accurate. The Everline pipeline controller for MP69 verified that the flow rate was similar to that of Third Coast SCADA information.[18] At

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[15] There are alarms for pressure low and high, and the low pressure alarm was activated multiple times during the controller's shift.
[16] During NTSB interviews and discussions with company officials, no one value for an imbalance that would lead to a shutdown was described or agreed to by those interviewed.
[17] The information available from the platforms was includes flow rate, platform run state (running or down), pressure, temperature, accumulator values – run/status included for the accumulator values besides numbers, and loss of communications. The post-accident investigation determined that there was no loss of communication reported by the operator or found in SCADA data to have occurred.
[18] According to the *Third* Coast *Operations & Maintenance Manual Hazardous Liquids 195*, control room responsibilities during an Abnormal Operation include notifying on call field personnel, and/or Pipeline Supervision and others as appropriate regarding each abnormal condition. Further, operations may continue when it is deemed safe by Control Room Operations. Abnormal Operations included: Pressure/flow rate deviations that cannot be explained; and unexplained line imbalance as determined by routine over/short determination.

8:53 p.m., the pipeline controller switched meters to see if the flow rate (Barrels per hour, BPH) would change value.[19]

At 8:55 p.m. the pipeline controller called the Third Coast field technician and expressed his concern regarding the volume differences and the pressure changes; and that the system imbalance was not improving.[20] The pipeline controller told investigators that during their conversation, he told the field technician that "we need[ed] to shut down the system as a precaution" and that the field technician told him, "Not to shutdown to give it a bit more time and see if accumulations and flow rates would start going the other way (i.e., improving or reducing the imbalance)." The field technician, who was at his residence (and without his computer) at the time of this call, indicated that he would call other field technicians (from Crescent) currently working at the MP69 to see if there were any anomalies at that platform.

The field technician told investigators that he recalled that the pressure was in the 400 to 500 range, which he said was common for them; and that the pipeline had been experiencing higher than normal pressure - around 700 psig - because of some pumps conditions (faults) being downstream. He also told investigators that a typical differential pressure was about 40 psig.

The field technician also told investigators that it was not part of his job to determine whether there is a leak on the pipeline system (beyond visual observations of a spill). Beyond visual training, he said that he was not specifically trained on how to recognize whether there might be a leak on the line.

At 9:03 p.m., the field technician called the pipeline controller and reported that everything looked normal at MP69 (based on his discussion with other personnel working at MP69). (The field technician told investigators that personnel at MP69 perform a visual inspection for a leak, but they do not go to the meters or valves for an inspection). The pipeline controller informed the field technician that accumulation receipts and accumulation deliveries differences were growing and that he (the pipeline controller) felt that they needed to shut down the system. The pipeline controller told investigators that, "once again he assured me that everything

[19] During this period, the pipeline controller told investigators that he was also responding to alarms and phone calls on the other systems for console OCC2 which includes gas and liquid pipelines.
[20] The official title of this Third Coast employee is "field operator" but will be referred to in this report by his informal title of "field technician."

was fine that he thought that the equipment / meters reading was most likely the problem."

The field technician told investigators that meter issues occurred in the past due to some paraffin and debris clogging the meters and causing an imbalance in volume. He stated, "I guess because of our past issues that we've had with the meters and what we've had for pressures and whatnot, everything seemed to have been a normal operating pressure for us at the time of this incident."

About 9:05 p.m. the pipeline controller called personnel at Oxy platform and asked for production flow rate to MPOG (in order to verify flow rate). Their flow rates matched his meter readings. At 9:15 p.m. the pipeline controller called personnel at Oxy platform VK-915 and asked him for production flow rate. Their flow rates also matched his meter readings.

The pipeline controller then decided to go from 2 active meter runs to 1 to see how the pressure would react on the MPOG pipeline. After about 20 minutes, he noted that the pressure increased by 100 psig on the entire MPOG system. At 9:45 p.m., the pipeline controller called the field technician to inform him that the MPOG pipeline pressure had increased. The pipeline controller told the field technician that the accumulation receipts and accumulation deliveries difference was growing. The pipeline controller told investigators that the field technician had again assured him that everything was fine on the pipeline, and that the meter's reading was most likely the problem.

About 10:15 p.m., the pipeline controller called Third Coast OCC2 Supervisor. The pipeline controller told investigators that "I made him aware of the events, the trends that I had analyzed and my concerns, I also informed him of the multiple calls to Third Coast field [technician] as well as the field technician's responses that he thought it was a meter problem at MP69. I also mentioned that MPOG pipeline psig increased by 100 psi in around 20 minutes." The pipeline controller also told investigators that he told his supervisor that he suggested to the field technician that the pipeline be shut down. According to the pipeline controller, the supervisor told him to go with the field technician's recommendation and keep the pipeline operational. This was the only conversation between the OCC2 Supervisor and Controller reported to have occurred during this shift.

The OCC2 Supervisor told investigators that, based on the information communicated to him during that phone conversation, he believed there was a measurement issue. He stated, "The flows were matching. The pressure(s) are increasing. In this scenario everything is fine… On a liquid system…that sounds like normal operations to me… there was nothing further to be discussed. I was comfortable enough to go back to bed." Following the accident, the supervisor told colleagues that during his phone conversation with the pipeline controller the pressure fluctuations were not disclosed to him.[21]

At 10:27 p.m., the field technician called the pipeline controller to discuss recent events on the MPOG system. The pipeline controller did not enter the 22:30 imbalance reading. At 10:57 p.m., the field technician again called the pipeline controller.

The pipeline controller told investigators that during his shift he had routinely expressed his concerns to the technician about the ongoing situation; and the technician routinely assured him that it was most likely due to equipment failure.

At 12:29 a.m. (November 16) the flow meters at MP69 went to zero flow, and pressure was increasing on MPOG and MP69.[22] Platform MP69 PLC is programmed to shut down the motor operated valves (MOV) of any utilized meter if the flow rate goes to zero. The pipeline controller was waiting for the MOVs to close. However, the valves did not close, and the pipeline controller was unclear why this did not occur.[23] He told investigators that, at that time, he believed that the PLC issue was a factor in the overall situation. He told investigators that the PLC not shutting down the active meters at MP69 "led me to believe that in fact a PLC issue was playing a role in this whole event and [the field technician] was correct in his assumption." The pipeline controller then switched meter runs, but saw no difference in flow rates. His SCADA commands to open or close the MOVs on the meter runs at MP69 were not successful. The field technician told investigators that MOVs not operating properly is

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[21] The OCC2 Supervisor's statement was made during the November 17, 2023, meeting with company officials that discussed the pipeline controller's employment termination.

[22] The OCC2 Operations Supervisor told investigators that he had never before seen a zero flow rate at MP69. Controllers were not required by written procedures to take an action when MP69 had zero flow.

[23] Third Coast Midstream officials told the NTSB that, according to MPOG OCC Daily Logger, the only day in 2023 on which valves 301, 303 and 305 appear to have not closed properly was November 15, 2023.

“definitely not a common issue. We’ve always had pretty good control of our valves there remotely.”

Post-accident, the Third Coast Pipeline Controller Lead, who had reviewed the SCADA and logger data following the event, told investigators that both the emerging flow and the pressure data gave him concerns.[24] He had concerns about the MPOG system based on the imbalance that began to grow around 7:30 p.m. that continued for five hours. He considered this, “very indicative of an issue.” That, along with the pressure trend and the zero flow rate at midnight (the latter he considered “the number one red flag”), would have warranted shutting down the pipeline around midnight. Procedures for the controllers did not require different actions of the controller upon zero flow at MP69.

About 1:00 a.m., the pipeline controller called the field technician and informed him of zero flow rate through MP69, and that the PLC was failing to close active meter run. (Meters had lost differential pressure and stopped working). According to the pipeline controller, the field technician continued to assure him that most likely it was an equipment failure. The field technician told investigators that he could not recall if the pipeline controller communicated that there was zero flow. He told investigators, “If I had seen some zero flow rate … that all would have indicated a major pressure drop.”

Also at 1:00 a.m. the electronic Daily Logger stopped working, and the pipeline controller began keeping notes in a notebook. At 2:55 a.m., the Daily Logger started working again but this was after the normal 2:30 am reading would have been entered.

At 1:30 a.m., the pipeline controller called Everline pipeline controller and requested that a platform operator at MP69 perform a walk through to try to spot an issue with equipment. At 1:46 a.m., the pipeline controller opened meter run 5 to check for flow rate. At 1:55 a.m., the Everline pipeline controller said that their field technician walked MP69 to check equipment and didn’t find any problems.

Upon leaving the shift, the controller performed the shift change and informed the incoming controller of the concerns about the MPOG pipeline and specifically

[24] The shift lead had not been notified of any issues prior to his arrival for his 0600 shift on November 16.

addressed with the incoming lead controller his concerns before leaving the location before the lead had arrived at the console and before the lead talked with the current incoming controller.

At the start of the 6:00 a.m. shift on November 16, the incoming pipeline controller, along with the pipeline controller lead, reviewed the OCC2 Daily Logger and notes, examined trends for pressures and flows from the previous shift and noted the zero flow reading at Crescent (MP69) at midnight. They became concerned about MPOG to Everline / Crescent. They communicated with other personnel, including the OCC2 Supervisor, who purportedly was surprised to find out that there was a zero flow reading at Crescent. Around 6:30 a.m., the decision to shut down the MPOG system was made (collectively by the 3 individuals reviewing the information – the OCC2 Supervisor, the Pipeline Controller Lead and the Incoming Pipeline Controller). Subsequently, they began calling the highest producing producers first and then those producers not running regarding the shutdown. They told investigators that the system was completely shut down in less than an hour. The OCC Supervisor told investigators that at 07:00 a.m. there was nothing more that could be done from the control room with the field once the inlet valves are shut. After field operations had been contacted, everything was logged that occurred on the morning of November 16 and back through to the evening of November 15.

Details of the actions to shut down the pipeline are contained in Appendix A: "LMS OCC Daily Log Entry: 17783."

Post-Accident Meeting with Third Coast Officials

At a post-accident meeting with company officials to discuss the pipeline controller's termination on November 16, 2023, the pipeline controller told officials the field technician "has guided me through different scenarios in the past and due to his knowledge and experience, this is what lead me to trust him 100% in this case." The Director, Operations Control Center (Gary Martinez) told the pipeline controller, "there was a hydraulic issue, and the indicators were obvious, you should have shut the line down as you did not need [the pipeline technician's] permission. You have been trained on policy & procedure. You are the one who has visibility of the data." The pipeline controller stated, "I should have shut down the line and not listened to [the field technician]."

The reasons cited for the pipeline controller's termination were "Lack of communication, [and] failure to follow safety training policy and procedure."

H. OPERATIONS CONTROL CENTER - TRAINING

Pipeline Controller Training

The OCC2 Operations Supervisor described pipeline controller training as a three-step process. This training takes 3-4 months to complete. During Phase 1 (2-weeks long) the trainee is given a general introduction of the IT systems and works with an experienced controller. Phase 2 reviews scheduling, and the commercial aspects of the system and new trainees can log on the console. This phase of training is done on the console for 3-8 weeks in duration (under a qualified controller's review). Phase 3 starts with specifics of start/stop, open/close, trend pressures, find MOP, covers specifics of each pipeline system, and ends with preparation for final qualification. During this period a supervisor will randomly ask questions of the new trainee and have the new trainee explain elements of response. If the trainee passes all three Phases, then the Operation Qualification (OQ) occurs.

The last phase of training also included a 60-question exam on Emergency Operations (EOC) and Abnormal Operating Conditions (AOC). After trainees pass these requirements, they will operate a console without direct supervision by a qualified controller. Requalification is required of controllers every 3 years, which is performed by the Operations Supervisor.

The Operations Supervisor is not logged in to a console, but can match or watch what was or is happening and would oversee new controller training, develops questions on training scenarios and makes assignments for new controllers to an experienced controller for On-The-Job (OJT) training. The Operations Supervisor switches up the assignments so that more than one experienced and qualified controller is involved with OJT. Training for a new controller covers site-specific aspects after the switching of OJT assignments has occurred. The Operations Supervisor performs the initial OQ review, and then a final OQ test is completed.

Pipeline controller training related to SCADA operations includes (but limited to): line imbalance, mass balance calculations (O/S), unexplained pressure or flow deviations, and indications of a potential leak.

Pipeline controllers are not cross trained, so controllers are dedicated to either OCC1 or OCC2 (as are Shift Leads). However, OCC1 controllers could assist OCC2 controllers with phone calls during emergency situations.

The Operations Supervisor told investigators that rotating shifts and the long shifts are the biggest challenges for new controllers. The challenges of working the SCADA system include staying on top of everything, understanding pressures and restrictions, and balancing the system.

Abnormal Situations

Third Coast document, "Receiving Notice and Responding to Abnormal Situations OM-195-10.1" discusses abnormal situations.

Examples of abnormal operations include:

1. Pressure/flow rate deviations that cannot be explained.
2. Unexplained line imbalance as determined by routine over/short determination.
3. Unintended valve closure or shutdown.
4. Operation of any safety device.
5. Loss of communication that impedes the safe operation of the system.
6. Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property."

An abnormal operation also includes "Valve that does not respond to a command, AND that results in system limits being exceeded."

Control room responsibilities during an Abnormal Operation include notifying on call field personnel, and/or Pipeline Supervision and others as appropriate regarding each abnormal condition. Further, operations may continue when it is deemed safe by Control Room Operations.

I. PIPELINE CONTROLLER AND FIELD TECHNICIAN

1. Training and Experience

a. Pipeline Controller. The pipeline controller had worked for Third Coast as a controller since February 2015. He had been OQ qualified for this position. Prior to that he worked for Enterprise Products as a Liquids pipeline controller from

December 2010 to January 2015; and at Kinder Morgan as a liquids pipeline controller from February 2007 to December 2010. He also worked as a field operator at Kinder Morgan from February 2004 to February 2007.

The pipeline controller's training to become a pipeline controller at Third Coast included online training and On-The-Job training, which he believed helped him prepare for how to detect a leak and what actions needed to be taken. He told investigators that "general training was provided to look for pressure changes and flow rate changes. If an unsuspected pressure change or flow rate changes were detected, start to troubleshoot SCADA tags and log the event, to include the time and the personnel who [were] contacted."

The pipeline controller's training records (CRM Review) indicated that the pipeline controller was OQ Requalified (by the OCC2 Supervisor) on the following operations:

- Facility Knowledge
- Controlling Flow and Pressure
- Remotely Operate Valves
- Starting Up and/or Shutting In a Pipeline Segment
- Remote Startup, Operations and Shutdown of Pump Stations
- Respond to Alarms
- Emergency Response

Other training received by the pipeline controller includes (but not limited to): Normal Operations, O&M Sect 11 EOP, OCC Weekly Training, Controller Training (multiple Phases which include Online Resources, SCADA System, SCADA Operation, Pipeline Systems, and Alarm/Leak Response/AOC/Emergencies, Scheduling, Shift Change, Fatigue Management), and Tabletop AOC/EOC Drill: Scenario – Hi-Hi pressure.

On August 31, 2023, the pipeline controller had successfully passed the *Operator Qualification Task List* and *Abnormal-Emergency Operations Test*. On the latter test, he correctly answered the following questions:

> "Controllers have the authority and responsibility, without referral to/from management for approval, to shut down any pipeline system upon receiving a report or indication of an emergency condition." (The controller answered "yes").

"If the abnormal condition persists to the point of meeting the criteria of an emergency, what will the controllers do?" (The controller answered, "Shutdown pipeline until condition is corrected.")

"If a controller is unable to determine if a leak has occurred, what should they do?" (The controller answered, "shutdown the pipeline, and contact field personnel.")

In a prior incident, the pipeline controller had responded to a pipeline crude oil leak on a different pipeline system, the Great Salt Plain Midstream (GSPM) system; however this had visual confirmation of a leak and field technicians responded to the site to investigate. He was called by an operator informing him that liquid was coming out of the ground near or at a delivery meter skid. The pipeline controller immediately shut down the pipeline called the GSPM field operations manager, who sent field technicians to the site to investigate.

b. Field Technician. The field technician earned his high school diploma then began working in the oil industry working as a measurement technician, and has performed those duties since 2008. He had worked in both the oil and gas industries. In 2015 he was contracted – and eventually hired as a full-time employee with MPOG as an operator (i.e., field technician). He had experience and/or qualifications as a certified measurement technician, control center communications, lockout/tagout procedures, and has been OQ certified & T2 (Production Safety Systems Training) certified.[25] He had completed courses in 2022 that included Incident Command Systems, Hazard Identification, and Incident/Accident Investigation.[26] At the time of the accident he also was assigned to other Third Coast assets.

2. Performance Evaluations

a. Pipeline controller

The pipeline controller's last Third Coast Annual Performance Review was January 24, 2023. On a rating scale of 1-5 (1-Unacceptable, 2-Below Expectations, 3-

[25] T2 involves knowledge and ability to operate an oil and gas production facility both onshore and offshore.

[26] The field technician's routine included working on valves, measurements, meter proving, testing, and using pipeline inspection gauges. He also assisted with other pipeline systems performing similar work.

Meets Expectations, 4-Exceeds Expectations, 5-Outstanding), the pipeline controller was consistently rated 3- Meets Expectations - on each competency: Job Knowledge, Personal Effectiveness, Communication & Teamwork, and Ethics & Safety.

When discussing aspects of training with other controllers, the controller on duty at the time of the accident was described as a good controller and at least one other controller described that the controller did what he would have done on that evening.

b. Field technician

The field technician's Third Coast Annual Performance Review (December 31, 2022) rated as "Meets Expectations" or "Exceed Expectations" on the competencies.

3. Work/Rest Schedule

General. Pipeline controllers at the Operations Control Center follow the Dupont shift schedule, which requires 12 hour shifts to provide 24-hour shift coverage. The Dupont schedule for Third Coast controllers uses a 4-week rotation starting on a Friday night with working 4 night shifts, 3 days off, 3 days on duty, 1 day off duty, 3 night shifts, 3 days off, 4 days on duty, then off duty for 7 days.

a. The pipeline controller went on duty at 1800 Wednesday November 15, 2023, and was on duty at the time of the spill for MPOG assets, was working his second consecutive night shift (6:00 p.m. to 6:00 a.m.). His prior shift on Tuesday also began about 6:00 p.m. He had been off duty the two prior days (Monday and Sunday).

b. The field technician went on duty Wednesday November 15, 2023, and worked from 6:00 a.m. to 4:00 p.m. (He was off duty when he received calls from the pipeline controller Wednesday night). On Tuesday November 14 he worked from 5:00 a.m. to 5:00 p.m. On Monday he had worked from 6:00 a.m. to 4:00 p.m. He was off duty three consecutive days prior to that.

4. Medical / Health / Post-accident Toxicology

a. The pipeline controller told investigators that he was in good health, and denied having any short term (colds or allergies) or long term / chronic medical conditions. He had not been diagnosed with any type of sleep disorder. He told investigators that he felt rested at the start of his shift.

b. The field technician told investigators that his overall health was good and that he did not have any colds or allergies at the time of the event. He also stated that his sleep was good.

5. Post-accident toxicological testing

On November 16, 2023, the pipeline controller was notified of his need to take a post-accident toxicological test. He then drove one hour to a collection facility. At 4:28 p.m., he provided breath and urine specimens. The results for alcohol were negative, as were all other substances tested for under the DOT/HHS Drug Panel.

On November 16, 2023, the field technician was notified of his need to take a post-accident toxicological test at Plaquemines Medical Center in Port Sulphur, LA. His drive to that location was about 2½ hours. At 4:40 p.m., he provided urine specimens (DOT/HHS Drug Panel). The results were negative for all substances tested for. He was not administered a breath test for alcohol.

J. SCADA FACTUAL REPORT

SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

Third Coast uses a Supervisory Control and Data Acquisition (SCADA) system to monitor the operation of the MPOG pipeline system. The SCADA system collects real-time data from sensors located in the pipeline system, processes the data, and then displays the data on monitors in the control room for the pipeline controllers and shift leads to see and use to make decisions about the operation of the pipeline system, as necessary. The SCADA system measures several parameters within the pipeline system, including but not limited to flow rate, pressure, and volume accumulator values.[27] These parameters are measured for each of the seven assets that feed crude oil into the MPOG pipeline system, including MP-123A, MP-144A, MP-270B, MC-127A, MP-281A, VK-823A, and VK-915A, as well as for the Crescent-owned MP-69A station where crude oil is received from the MPOG pipeline system.

On the evening of November 15, 2023, the SCADA system recorded changes in flow rate and pressure for the MP69 station with no change in operating conditions for any of the seven assets that fed into the MPOG pipeline system.

Beginning at roughly 6:12 p.m. on the evening of November 15, 2023, recorded SCADA data indicates a decrease in flow rate into the MP69 station (Figure).[28] This initial decrease in flow rate is followed by a quick rebound at around 6:24 p.m. that continues until about 6:35 p.m., before pressure decreases again until about 6:42 p.m., before increasing again until about 6:50 p.m., at which time the flow rate begins to significantly decrease. By around 8:31 p.m. the recorded flow rated had dropped from 3,493 barrels per hour (bph) to 1,620 bph; a decrease of more than 1,870 bph. The recorded flow rate rebounded and experienced some increases and decreases over the next hour or so, but by around 9:49 p.m., the flow rate had dropped to roughly 1,242 bph. The sporadic increases and decreases continued over the next several hours, dropping as low at 637 bph at around 12:05 a.m. on the morning of November 16, 2020, before a 0 bph flow rate was recorded for the MP-69A station at approximately 12:29 a.m. Recorded data indicates a 0 bph flow rate into the MP-69A station until about 2:26 a.m. when it increased slightly for about 12 minutes and then went back to 0 bph at about 2:38 a.m. The recorded flow rate for

[27] MPOG only transports crude and never takes title to the product. At each of the assets that supply crude oil to the MPOG pipeline system, as well as at the MP 69 "A" station, each company has their own metering system that measures the volume of crude oil entering and exiting MPOG. The supplying oil meters are proved each month to ensure accuracy of the metered volumes, and the meter proving reports are submitted monthly to BSEE, as well as to the buyer (pipeline company) and the seller (supplying company). See the *Pipeline Operations and Integrity Management Group Chair's Factual Report* within this docket for more information.
[28] MP123CRUDE_STN_FLOWVOLBPH

the MP-69A station increased slightly again on a couple more occasions over the next few hours before settling back at 0 bph at around 5:20 a.m. where it remained.

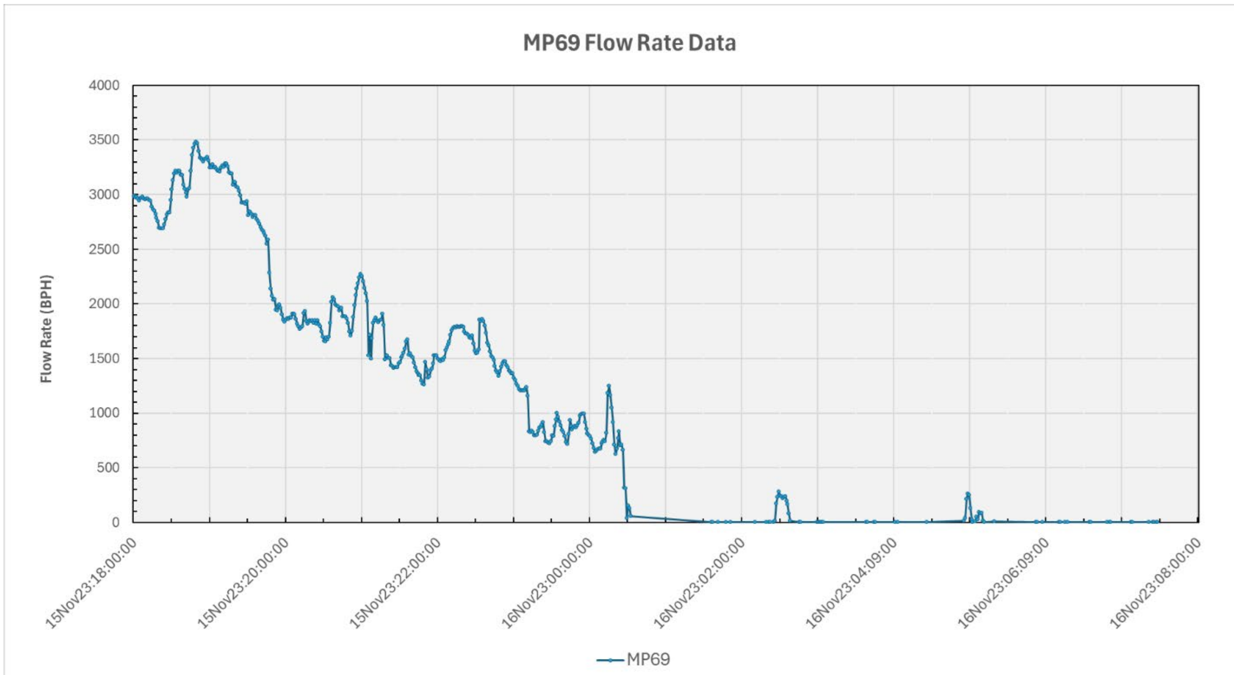

Figure 4. *MP-69A Flow Rate Data (November 15 – 16, 2023)*

Recorded flow rate data for each of the assets that introduced crude oil production into the MPOG pipeline system was consistent with the volume of product and timing of when the product was fed into the pipeline according to SCADA data and information provided by each of the assets. MC-127A introduced the largest amount of crude oil in the MPOG pipeline system and did so on a continuous basis during the timeframe in reference.[29] Recorded flow rate data for MC-127A indicates that the flow rate remained relatively constant between 6:00 p.m. on November 15, 2023, until about 6:35 a.m. on the morning of November 16, 2023, when the asset commenced pump shutdown operations, which caused the flow rate to decrease (Figure 5).[30,31] VK-915A introduced the second largest amount of crude oil into the MPOG pipeline system during this timeframe and did so on a continuous and consistent basis.[32] Like MC-127A, recorded flow rate data for VK-915A indicates a relatively constant flow rate until roughly 6:18 a.m. at which time the asset ramped down production into the MPOG pipeline system, resulting in the decreased flow rate.[33,34] MP-144A also introduced crude oil into the MPOG pipeline system on a

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[29] MC-127ACRUDEPLC_STN_INDVOLDAY
[30] MC-127ACRUDEPLC_STN_FLOWVOLBPH
[31] Occidental Petroleum Corporation - Response to NTSB - Gulf of Mexico (PLD24FR001)
[32] VK-915ACRUDE_STN_INDVOLDAY
[33] VK-915ACRUDE_STN_FLOWVOLBPH
[34] Occidental Petroleum Corporation - Response to NTSB - Gulf of Mexico (PLD24FR001)

continuous basis during this period, however on much lesser scale.[35] Like MC-127A and VK-915A, recorded flow rate data for MP-144A remained relatively constant during this timeframe until the asset shut down its pumps to the pipeline around 6:20 a.m.[36,37] During this timeframe MP-123A also introduced a small amount of crude oil into the MPOG pipeline system, but not on a consistent or continuous basis.[38,39] Recorded flow rate data for MP-123A is consistent with the times that crude oil was introduced into the MPOG pipeline system.[40,41] VK-823A also introduced a small amount of crude oil into the MPOG pipeline system over this timeframe, but not on a consistent or continuous basis.[42,43] Similar to MP-123A, recorded flow rate data for VK-823A is consistent with the timing of when crude oil was introduced into the MPOG pipeline system.[44,45] Neither MP-270B[46,47] nor MP-281A[48,49] introduced any crude oil into the MPOG pipeline system during this timeframe.[50,51] Accordingly, no flow rate data was recorded for either of the assets until 7:03 a.m. and 6:50 a.m., respectively, on the morning of November 16, 2023, when shutdown operations for these assets commenced.

[35] MP144CRUDE_STN_INDVOLDAY
[36] MP144CRUDE_STN_FLOWVOLBPH
[37] Cantium - Response to NTSB - Gulf of Mexico (PLD24FR001)
[38] (between roughly 7:00pm – 9:00pm and 4:30am – 7:00am)
[39] MP123CRUDE_STN_INDVOLDAY
[40] MP123CRUDE_STN_FLOWVOLBPH
[41] Arena Offshore - Response to NTSB - Gulf of Mexico (PLD24FR001)
[42] (between roughly 6:00pm – 6:15pm and 1:25am – 3:10am)
[43] VK-823ACRUDEPLC_STN_INDVOLDAY
[44] VK-823ACRUDEPLC_STN_FLOWVOLBPH
[45] W&T Offshore - Response to NTSB - Gulf of Mexico (PLD24FR001)
[46] Walter Oil & Gas - Response to NTSB - Gulf of Mexico (PLD24FR001)
[47] MP-270B was shut in at 8:15 a.m. on November 15, 2023, for maintenance repairs and was not online.
[48] TALOS - Response to NTSB - Gulf of Mexico (PLD24FR001)
[49] MP-281A pumps crude oil from its stock tank through the LACT unit and into the MPOG pipeline system once a day. At approximately 6:40 a.m. on November 16, 2023, the platform initiated the daily pump sequence and noticed that the LACT was down. The operator reset the LACT and began pumping. The platform received call from Third Coast around 7:00 a.m. notifying them that they would be shutting down the LACT due to a "Comms Issue at MP68".
[50] MP-270BCRUDE_STN_FLOWVOLBPH
[51] MP-281ACRUDEPLC_STN_FLOWVOLBPH

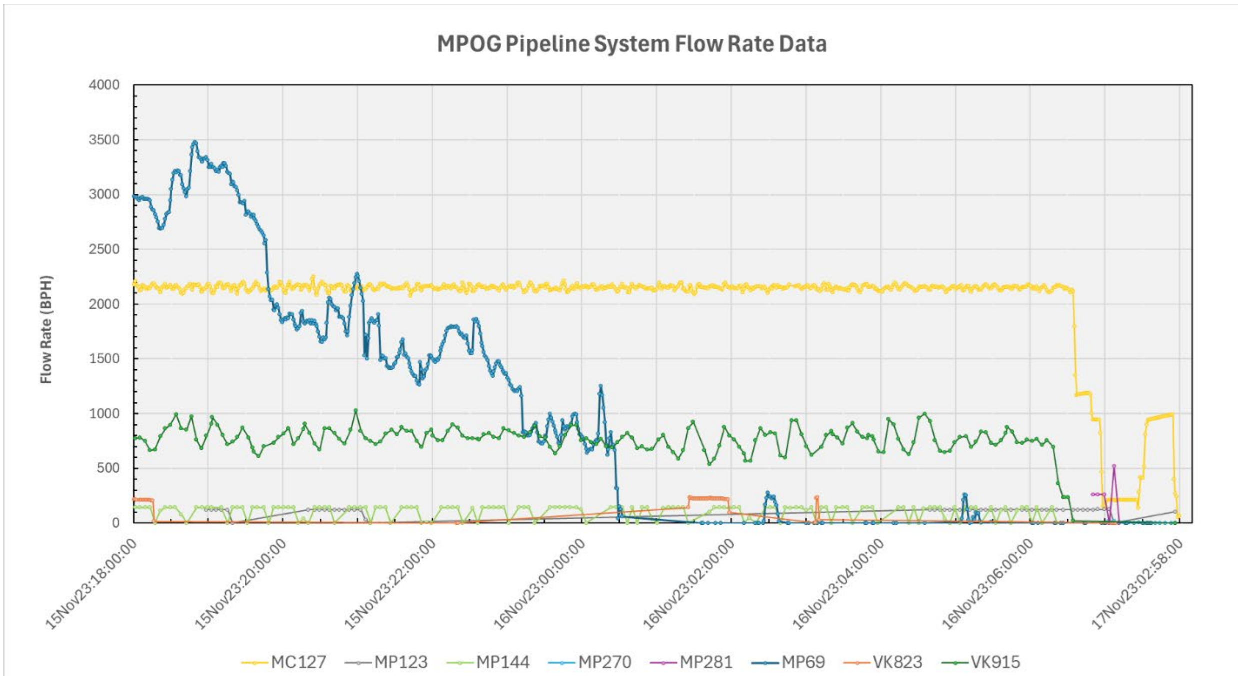

Figure 5. *MPOG Pipeline System Flow Rate Data (November 15 – 16, 2023)*

In terms of pressure changes, shortly after 6:35 p.m. on November 15, 2023, the recorded pressure at the MP-69A station began to decrease.[52] By 7:57 p.m., the recorded pressure decreased from 552 psig to 241 psig; a pressure drop of 311 psig (Figure 6). Following this initial decrease the pressure, SCADA data indicates that the pressure held in the same general range until around 8:15 p.m., at which time it began to increase. For roughly 20 minutes, between 8:15 p.m. and 8:35 p.m., the pressure increased over 50 psig before it once again began to decrease. By 9:17 p.m. the pressure had decreased to 226 psig before once again began to increase until it reached 374 psig at 9:49 p.m. After this time the pressure once again began to decrease until it reached 202 psig at 11:07 p.m., and then increased slightly before decreasing to 174 psig at 12:15 a.m. on the morning of November 16, 2023. At this time, the pressure began to once again increase and between about 12:42 a.m. and 5:27 a.m., held between roughly 274 psig and 358 psig, before ultimately decreasing to near zero pressure (~2 psig) at around 7:15 a.m. that morning.

[52] MP-69ACRUDEPLC_STN_PRPLINE

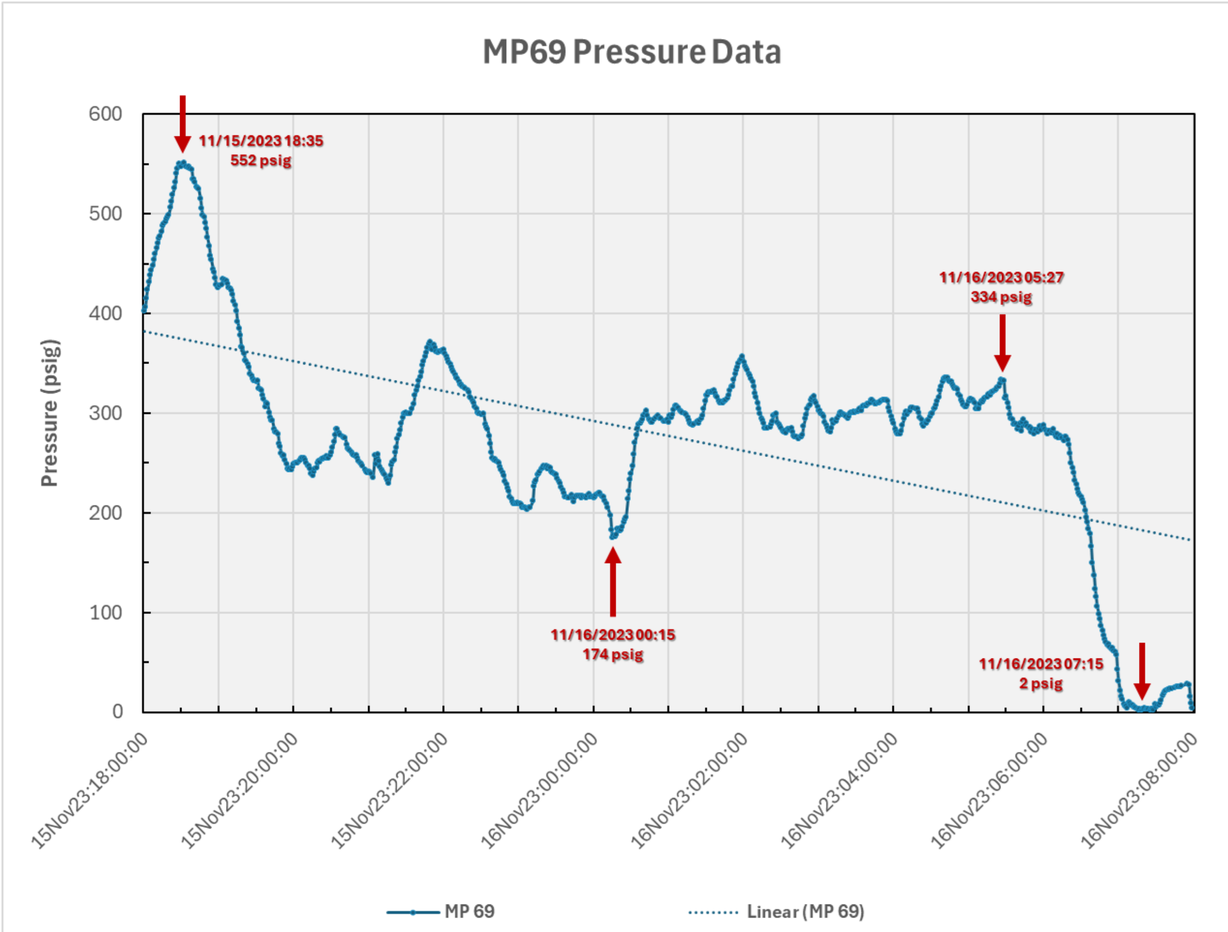

Figure 6. MP-69A Pressure Data (November 15 – 16, 2023)

Recorded pressure data for each of the assets that introduced crude oil production into the MPOG pipeline system was relatively consistent with that of MP-69A (Figure).[53] As previously mentioned, MC-127A introduced the largest amount of crude oil in the MPOG pipeline and did so on a continuous basis during this period. Recorded pressure data for MC-127A indicates a similar pattern as the one described above for MP-69A, just on a larger scale.[54] Recorded pressure data for VK-915A (the second largest producer) indicates a similar pattern to MP-69A.[55] Recorded pressure data for MP-144A (another continuous producer) also aligns closely with that of MP-69A.[56] Recorded pressure data for VK-823A (sporadic producer) is also relatively consistent with MP-69A.[57] Neither MP-270B nor MP-281A introduced product to the

[53] Note: MP123 introduced a small amount of crude oil into the MPOG pipeline, but not a consistent or continuous basis. No pressure data was recorded for MP123 during this timeframe due to a bad pressure transmitter.
[54] MC-127ACRUDEPLC_STN_PRPLINE
[55] VK-915ACRUDE_STN_PRPLINE
[56] MP144CRUDE_STN_PRPLINE
[57] VK-823ACRUDEPLC_STN_PRPLINE

MPOG pipeline system during this timeframe. Recorded pressure data for MP-281A[58] is like that of MP-69A, while recorded pressure data for MP-270B[59] appears to steadily decrease from 60 psig to 0 psig over this timeframe.

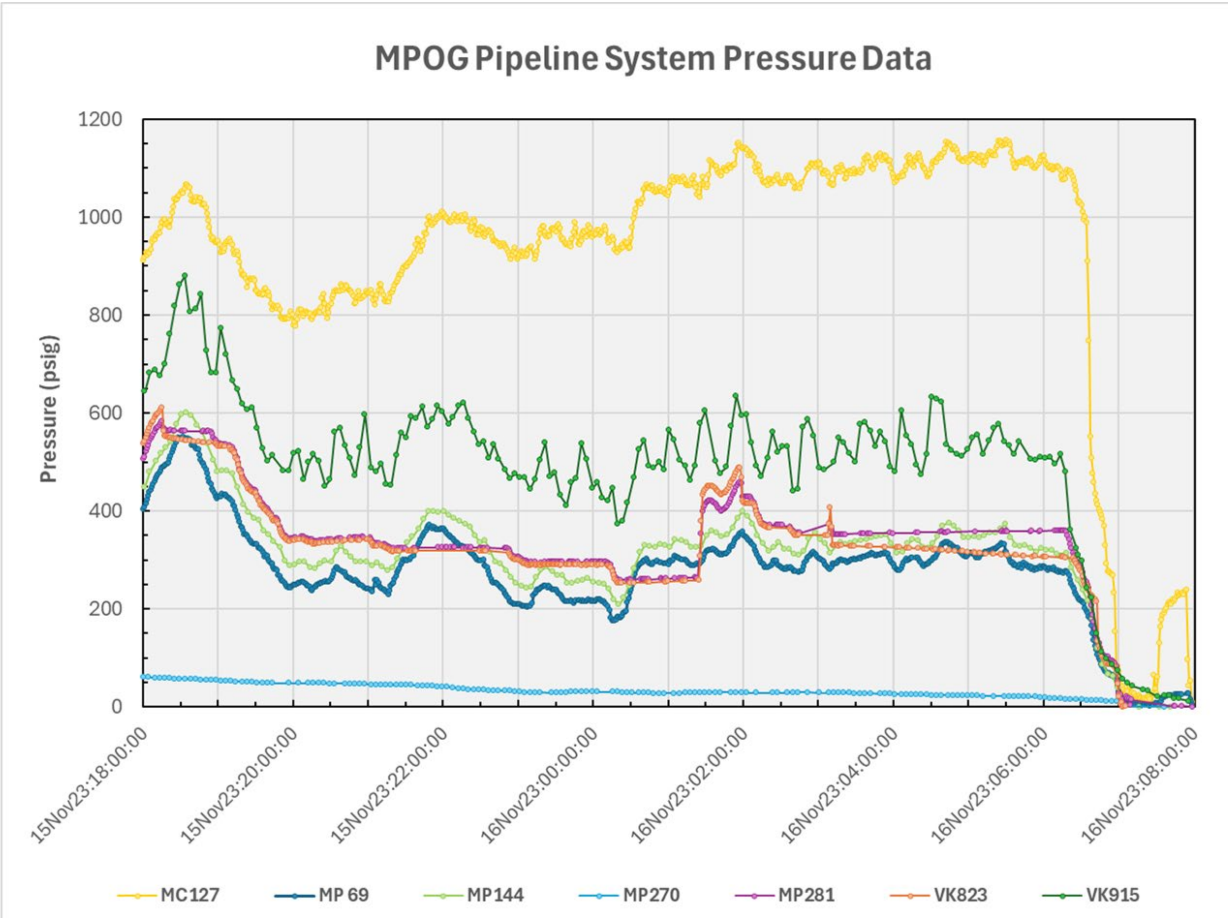

Figure 7. MPOG Pipeline System Pressure Data (November 15 – 16, 2023)

As previously mentioned, the SCADA system also records volume accumulator values for each of the seven assets that feed into the MPOG pipeline system and the MP-69A station.

Pipeline controllers are required to enter the volume accumulator flow values from SCADA into the OCC2 Daily Logger every four hours, to identify imbalances in the system. These entries, which are typically made at around 2:30 a.m., 6:30 a.m., 10:30 a.m., 2:30 p.m., 6:30 p.m., and 10:30 p.m., indicate the imbalance for past hour preceding the entry. On the evening of November 15, 2023, the OCC2 pipeline controller entered this information in the OCC2 Daily Logger at 6:33 p.m., noting an imbalance value of -174 barrels (

[58] MP-281ACRUDEPLC_STN_PRPLINE
[59] MP-270BCRUDE_STN_PRPLINE

).[60] Prior to his shift, the previous OCC2 pipeline controller had noted an imbalance value of 1 barrel at 2:38 p.m. The pipeline controller did not make any additional entries into the OCC2 Daily Logger during his shift. The OCC2 Daily Logger was reported to have stopped working between 1:00 a.m. and 2:55 a.m. on the morning of November 16, 2023.

Table 2. *OCC2 Daily Logger (November 14 – 16, 2023) showing growing imbalance beginning at 6:33 p.m. on November 15, 2023 (annotated by NTSB)*

ID	System	Receipt	Delivery	Net	Timestamp
7585	MPOG	2957	2878	-79	11/14/2023 2:30:00
7588	MPOG	3045	2754	-291	11/14/2023 6:29:00
7591	MPOG	3334	3259	-75	11/14/2023 10:32:00
7594	MPOG	3024	3087	63	11/14/2023 15:11:00
7597	MPOG	3197	3197	0	11/14/2023 18:30:00
7600	MPOG	2997	2849	-148	11/14/2023 22:53:00
7603	MPOG	2917	3055	138	11/15/2023 6:29:00
7606	MPOG	3454	3685	231	11/15/2023 10:38:00
7609	MPOG	3056	3057	1	11/15/2023 14:38:00
7612	MPOG	3264	3090	-174	11/15/2023 18:33:00
7615	MPOG	533	0	-533	11/16/2023 7:00:00
7618	MPOG	0	0	0	11/16/2023 10:34:00
7621	MPOG	0	0	0	11/16/2023 14:36:00
7624	MPOG	0	0	0	11/16/2023 18:27:00
7627	MPOG	0	0	0	11/16/2023 22:41:00

Review of recorded volume accumulator flow values between 6:30 p.m. on November 15, 2023, and 6:30 a.m. on November 16, 2023, indicate that the imbalance continued to increase significantly over this timeframe, reaching roughly 26,194 barrels by 6:30 a.m. (Table 3). The recorded volume accumulator flow values from SCADA were relatively consistent with the metering data provided by each of the seven assets. Once the companies were notified of the MPOG pipeline system issues (Table), the companies took action to shut down their supply to the pipeline system.

[60] MPOG-010707_TRADE SECRET-CBI_OCC Logger - Over and Short Data - 11-14 to 11-16

Table 3. Summary of hourly accumulator values for assets feeding into MPOG pipeline system and exiting the system at the MP-69A station showing the growing imbalance (November 15 – 16, 2023)

Timestamp	BBLs Received to MPOG Pipeline System							Total BBLs Received (All Producers)	Total BBLs Delivered (MP 69A)	Net BBLs (per hour)	Cumulative Net BBLs (since 11/15/2023 17:30)
	MP-123A	MP-144A	MP-270B	MC-127A	MP-281A	VK-823A	VK-915A				
11/15/2023 18:30	-	97	-	2,153	-	125	827	3,202	3,011	(191.00)	(191.00)
11/15/2023 19:30	49	109	-	2,156	-	-	816	3,130	3,189	59.00	(132.00)
11/15/2023 20:30	22	106	-	2,149	-	-	801	3,078	2,109	(969.00)	(1,101.00)
11/15/2023 21:30	75	92	-	2,152	-	-	794	3,113	1,815	(1,298.00)	(2,399.00)
11/15/2023 22:30	-	82	-	2,147	-	-	857	3,086	1,559	(1,527.00)	(3,926.00)
11/15/2023 23:30	-	90	-	2,155	-	-	847	3,092	1,258	(1,834.00)	(5,760.00)
11/16/2023 0:30	-	83	-	2,148	-	-	748	2,979	793	(2,186.00)	(7,946.00)
11/16/2023 1:30	-	97	-	2,147	-	20	783	3,047	5	(3,042.00)	(10,988.00)
11/16/2023 2:30	-	65	-	2,149	-	106	710	3,030	13	(3,017.00)	(14,005.00)
11/16/2023 3:30	-	101	-	2,148	-	6	785	3,040	26	(3,014.00)	(17,019.00)
11/16/2023 4:30	-	76	-	2,148	-	-	788	3,012	-	(3,012.00)	(20,031.00)
11/16/2023 5:30	108	85	-	2,153	-	-	799	3,145	21	(3,124.00)	(23,155.00)
11/16/2023 6:30	126	79	-	2,148	-	-	686	3,039	-	(3,039.00)	(26,194.00)
11/16/2023 7:30	66	-	2	591	56	-	4	719	-	(719.00)	(26,913.00)
11/16/2023 8:30	56	-	-	-	-	-	-	56	-	(56.00)	(26,969.00)

Table 4. Summary of notification of MPOG pipeline system issues provided to assets feeding into pipeline

Asset Name	Operator Name	Notification Time on November 16, 2023	Notification Party
MP-123A	Arena Offshore, LP	n/a	n/a
MP-144A	Cantium, LLC	~6:10 - 6:20 a.m.	Third Coast
MP-270B	Walter Oil & Gas Corporation	~10:00 a.m.	BSEE
MC-127A (Horn Mountain)	Occidental Petroleum Corporation ("OXY")	~6:14 a.m.	Third Coast
MP-281A	Talos Energy Ventures, LLC	~7:00 a.m.	Third Coast
VK-823A	W&T Energy VI, LLC	morning	Third Coast
VK-915A (Marlin)	Occidental Petroleum Corporation ("OXY")	~6:13 a.m.	Third Coast

ALARMS AND LOGIC

Review of alarm and event log data for the MPOG pipeline system from November 15 – 16, 2023, indicate that the decrease in flow rate to MP-69A did not trigger any alarms in the SCADA system.[61] The growing volume accumulator

[61] MPOG-010687_TRADE SECRET-CBI_OCC2_Alarms & Events_11-14 - 11-16

imbalance also did not trigger any alarms in the SCADA system.[62] Third Coast confirmed that there were no flow rate alarms or imbalance alarms enabled in the SCADA system at the time of the incident. With regards to recorded pressure for MP-69A, multiple visual "Low Limit Exceeded" alarms were triggered in the SCADA system beginning at 7:37 p.m. on November 15, 2023, and continuing through 5:38 a.m. on November 16, 2023 (Table 5).[63] Each of the low-pressure alarms was triggered when the recorded pressure for MP-69A dropped below 300 psig, the programmed low limit threshold for MP-69A. In each case the alarm was either acknowledged by the OCC2 pipeline controller and then returned to normal once pressure exceeded 300 psig or just returned to normal once pressure exceeded 300 psig without any acknowledgement.[64] None of the low-pressure alarms initiated automatic shutdown of the system by procedure or any other automated action, nor were they programmed to do so. No additional pressure alarms related to the MPOG pipeline system were recorded during this timeframe.[65]

[62] MPOG-010687_TRADE SECRET-CBI_OCC2_Alarms & Events_11-14 - 11-16
[63] MPOG-010687_TRADE SECRET-CBI_OCC2_Alarms & Events_11-14 - 11-16
[64] The low-pressure alarm was designed to clear and return to normal on its own whenever the pressure increased to over 300 psig. Acknowledgement of the alarm by the OCC2 pipeline controller was not required for the alarm to clear and return to normal.
[65] Except for low-pressure alarms for VK-823A and VK-915A on November 16, 2023, at 6:43 a.m. and 6:34 a.m., respectively, during shut down of the MPOG pipeline system.

Table 5. Recorded Low-Pressure Alarms for MP-69A Station (November 15 – 16, 2023)

Tag	Alarm Date	Alarm Time	Tag Value	Information
MP69CRUDEPLC_STN_PRPLINE	11/15/23	19:37:48	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/15/23	19:38:16	308	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/15/23	19:40:21	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/15/23	19:48:43	270	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/15/23	21:30:32	301	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/15/23	21:30:43	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/15/23	21:30:49	300	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/15/23	21:34:13	302	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/15/23	22:27:36	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/15/23	22:32:29	301	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/15/23	22:32:59	296	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/15/23	22:38:08	264	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	0:42:20	302	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	0:43:01	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	0:43:09	300	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	0:43:11	301	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	0:43:22	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	0:44:45	294	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	1:04:14	301	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	1:10:52	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	1:11:03	301	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	1:11:12	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	1:11:40	300	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	1:28:19	302	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	2:13:16	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	2:20:56	284	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	2:51:05	301	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:02:20	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:03:19	298	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:17:38	301	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:17:47	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:17:57	301	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:18:17	298	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:20:04	298	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:26:56	301	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:27:05	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:27:26	301	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:27:45	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:27:55	301	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:28:23	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:28:34	302	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:29:51	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:30:02	301	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:30:40	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:30:49	301	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:31:49	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:32:18	301	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	3:57:54	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:00:20	290	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:10:18	301	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:10:25	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:10:34	300	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:10:35	301	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:11:14	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:11:49	299	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:12:17	302	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:12:33	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:12:42	302	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:12:53	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:13:11	302	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:20:32	298	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:29:55	298	Acknowledge : Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:30:30	301	Returned To Normal
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:30:40	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	4:31:48	302	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	5:33:05	296	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	5:33:22	302	Returned to Normal from Low with no acknowledgment. Check event history
MP69CRUDEPLC_STN_PRPLINE	11/16/23	5:33:42	300	Low Limit Exceeded [300]
MP69CRUDEPLC_STN_PRPLINE	11/16/23	5:38:38	287	Acknowledge : Low Limit Exceeded [300]

PIPELINE SAFETY REGULATIONS AND GUIDANCE

The following Federal pipeline safety regulations and guidance applied to the MPOG pipeline system:

- 49 CFR 195.444, *Leak detection*. A pipeline must have an effective system for detecting leaks in accordance with 49 CFR 195.134 (by October 1, 2024) or 49 CFR 195.452 (by February 18, 2003).[66]

- 49 CFR 195.452(i)(3), *Leak detection.* An operator must have a means to detect leaks on its pipeline system, evaluate the capability of its leak detection means, and modify, as necessary, to protect the high consequence area (HCA). The operator's evaluation must consider several factors, including the pipeline's proximity to the HCA and the swiftness of leak detections.

- 49 CFR 195.452(i)(4), *Emergency Flow Restricting Devices (EFRD).*[67] If an operator determines that an EFRD is needed on a pipeline segment that is in an HCA in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, the operator must consider several factors, including the swiftness of leak detection and pipeline shutdown capabilities, the rate of potential leakage, the volume that can be released, the specific terrain within the HCA, and the benefits expected by reducing the spill size.

- 49 CFR 195.446, *Control room management.* Each operator must have and follow written control room management procedures. The procedures must define roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. The pipeline operator must provide its controllers with adequate information, including the information, tools, processes and procedures needed for the controllers to carry out their roles and responsibilities.

PHMSA has also developed Control Room Management Frequently Asked Questions, which are available on their website (see: Control Room Management FAQs | PHMSA (dot.gov)).

Additionally, PHMSA issued Advisory Bulletin ADB-10-01, *Leak Detection on Hazardous Liquid Pipelines,* on January 26, 2010.[68] ADB-10-01 calls for operators to perform an engineering analysis to determine if a computer-based leak detection

[66] These requirements do not apply to offshore gathering lines. The MPOG pipeline system is not a gathering line as defined by PHMSA's regulations, so these rules apply.
[67] EFRDs are check valves or remote control valves, as defined in 49 CFR 195.452.
[68] Federal Register: Pipeline Safety: Leak Detection on Hazardous Liquid Pipelines

system is necessary to improve leak detection performance and line balance processes. If the operator determines that a computer-based leak detection system is not needed, the operator "should perform the periodic line balance calculation process outlined herein and take any other necessary actions required to ensure public safety and protect the environment." In the background section of the Federal Register Notice for ADB-10-01, PHMSA explains that "When a pipeline operator has determined or selected to use a traditional line balance process through manual calculation, it is PHMSA's expectation that these operators would have systems configured and staffed in such a manner as to routinely, safely and accurately perform this manual calculation process at a maximum of one-hour intervals. The appropriate interval should be determined by engineering review but should not exceed one hour."

INDUSTRY GUIDANCE

American Petroleum Institute (API) Recommended Practice (RP) 1168, Second Edition, *Pipeline Control Room Management*, published February 2015 and reaffirmed October 2021. RP 1168 provides guidance on industry best practices for control room management. It addresses personnel roles, authorities, and responsibilities; guidelines for shirt turnover; information, tools, process and procedures operators shall provide to controllers; fatigue management; change management; lessons learned from operating experience; training; and workload of pipeline controllers.

API RP 1165, Second Edition, *Pipeline SCADA Displays*, published in December 2022. RP 1165 focuses on the design and implementation of displays used for the display, monitoring, and control of information on pipeline SCADA systems. The primary purpose of this RP is to promote the success of the controller to safely operate pipeline systems and to document industry practices. RP 1165 addresses Human Factors Engineering Considerations in display design; display hardware; display layout and organization; display navigation; object characteristics; object dynamics; control and selection techniques; administration; and display determination.

API RP 1175, Second Edition, *Pipeline Leak Detection – Program Management*, published April 2022. RP 1175 establishes a framework for Leak Detection Program (LDP) management for hazardous liquid pipelines. This RP covers several topics, including the need for operators to develop a strong leak detection culture. It provides examples of behaviors that indicate a strong leak detection culture, including "ongoing support toward continuously improving pipeline leak detection, even if the operator is meeting current leak detection goals" and "a focus on safe and reliable operation of the pipeline with no negative repercussions on the staff who take actions in response to leak indications (Shutdown when there is a leak indication.

When in doubt, shut down and then assess)." Other topics covered in RP 1175 include: leak detection program elements; management commitment and leadership; stakeholder engagement; risk assessment; selection of leak detection methods; performance targets, metrics, and performance indicators; testing; control center procedures for recognition and response; alarm management; roles, responsibilities, and training; reliability centered maintenance for leak detection equipment; overall performance evaluation of the LDP; controller training and retraining; management of chance; and improvement process.

API RP 1130, Second Edition, *Computational Pipeline Monitoring for Liquid Pipelines*, published November 2002. RP 1130 focuses on the design, implementation, testing and operation of computational pipeline monitoring (CPM) or leak detection systems that use an algorithmic approach to detect hydraulic anomalies in pipeline operating parameters. The primary purpose of these systems is to provide tools that assist pipeline controllers in detecting releases, including alarms and operational data displays that aid pipeline controllers in their decision-making.

PREVIOUS NTSB ACCIDENTS

In NTSB Safety Study NTSB/SS-05/02, *Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines¸* dated November 29, 2005, several NTSB-investigated accidents involving SCADA systems were reviewed.[69] These accidents occurred between April 1992 and October 2004.

More recent NTSB investigations of crude oil spills include:

March 11, 2022, Edwardsville, IL: At 8:15 a.m. local time, 22-inch diameter crude oil pipeline ruptured at a girth weld resulting in the release of about 3,500 barrels of crude oil, some of which entered Cahokia Creek. Pipeline controllers received both audible and visible alarms and isolated the segment in about eight minutes. The rupture occurred at milepost 6.2 on the Woodpat pipeline. No injuries or fatalities occurred as a result of the rupture.

October 1, 2021, Huntington Beach, CA: At 4:10 p.m. local time, San Pedro Bay Pipeline controllers received the first of a series of leak detection system alarms for their underwater pipeline. Over the next 13 hours, the controllers conducted seven pipeline shutdowns and restarts during troubleshooting of the alarms. At 6:04 a.m. on October 2nd, controllers shut down the pipeline for the eighth and final time. A pipeline contractor vessel crew visually confirmed a crude oil release at 8:09 a.m., and Beta Offshore, the pipeline operator, initiated an oil spill response. An estimated

[69] Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines (ntsb.gov)

588 barrels of oil leaked from the pipeline. Damage, including clean-up costs, was estimated at $160 million. There were no injuries. A post-accident underwater examination of the pipeline found a crack along the top of the pipeline within a section of the pipeline that had been displaced from its originally installed location. Additionally, scarring consistent with anchor dragging was identified on the seafloor near the crack location. The investigation determined that containerships *MSC Danit* and *Beijing* had dragged anchor near the pipeline on January 25, 2021, several months prior to the release.

Compiled by: /s/ Date: September 28, 2024

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