U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

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Houston TX 77074

NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

VIA ELECTRONIC MAIL TO: mrowland@third-coast.com

December 31, 2025

Matthew Rowland
President / CEO
Panther Operating Company, LLC
1501 McKinney St., Ste., 800,
Houston, TX 77010

CPF 4-2025-012-NOPV

Dear Mr. Rowland:

From November 16, 2023, to November 14, 2025, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code (U.S.C.), investigated an accident that occurred on the Main Pass Oil Gathering (MPOG) pipeline system. The MPOG is a hazardous liquid pipeline facility owned by Third Coast Infrastructure LLC (Third Coast) and operated by its affiliate, Panther Operating Company (Panther).[1]

The accident in question began on the evening of November 15, 2023, when a collet grip flange (CGF) connector, a device used to mechanically connect subsea pipelines, failed at Main Pass 69 (MP 69). MP 69 is an offshore area in the Gulf of America located in Louisiana state waters. The failure of the CGF connector resulted in a release of crude oil that lasted more than 9 hours. According to the National Transportation Safety Board (NTSB), the total amount of crude oil released during that time was approximately 27,000 barrels (1.1 million gallons).[2]

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[1] At the time of the accident, the MPOG system provided midstream services to crude oil producers in the Main Pass area and included 4 miles of 20-inch- and 61.8 miles of 18-inch-diameter hazardous liquid pipeline, with a maximum operating pressure of 1,950 pounds per square inch, gauge (psig). *PLD-24-FR-001: Supplemental Submission of Third Coast Infrastructure, LLC*, p. A-3.

[2] *Pipeline Investigation Report: PIR-25-02* (June 13, 2025).

Panther received the first indication of a release at around 7:30 pm on November 15, when a controller in the control room observed an imbalance in the input and output of the MPOG.[3] The controller then observed a series of pressure changes that continued until the flow meters to MP 69 indicated zero flow shortly at around 12:29 AM.[4] Despite these indications of a potential release, the controller did not order the MPOG to be shut down before his shift ended at around 6:00 am.[5] Instead, the MPOG remained in service until a new controller who reported for duty during the next shift ordered a shut down at around 6:30 am.[6]

On November 16, the US Coast Guard and Third Coast began the initial response to the accident. The Coast Guard subsequently convened a unified command comprised of several federal and state agencies, including PHMSA, the Bureau of Safety and Environmental Enforcement, the Louisiana Oil Spill Coordinator's Office, and the Louisiana Department of Wildlife and Fisheries, which coordinated oil spill response activities until April 2024. The NTSB also initiated an investigation, which concluded with the issuance of a Pipeline Investigation Report on June 13, 2025.[7]

As a result of PHMSA's separate investigation, it is alleged that Panther has committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (CFR). The items investigated and the probable violations are:

1. § 195.110 External loads

> **(a) Anticipated external loads (e.g.), earthquakes, vibration, thermal expansion, and contraction must be provided for in designing a pipeline system. In providing for expansion and flexibility, section 419 of ASME/ANSI B31.4 must be followed.**

Panther failed to provide for anticipated external loads in the design of its pipeline system in accordance with § 195.110(a). Specifically, Panther failed to account for anticipated external loads, including storm-related forces, geotechnical movement, loss of support, and pipeline displacement, in its use of a mechanical CGF connector at MP 69.

The CGF and the connected pipeline segments at MP 69 were not configured consistent with the expansion, displacement-stress relief, and load-management requirements of the installation environment. As a result, anticipated external loads were imposed directly on the CGF, creating conditions that compromised the integrity of the pipeline at MP 69.

[3] Responses to NTSB Information Request, p. 6.
[4] Responses to NTSB Information Request, p. 8; *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 14.
[5] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 15.
[6] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 16.
[7] *Pipeline Investigation Report: PIR-25-02* (June 13, 2025).

A CGF works by inserting the pipeline into the fitting, at which point twelve bolts are sequentially tightened to a specific torque such that mechanical teeth grip the pipe surface and keep the pipe in place and the end maintains a seal within the connector.[8] The manufacturer's specifications for the CGF at MP 69 allowed for a maximum insertion extent of 12 inches.[9]

In September 2004, Hurricane Ivan caused damage to various pipeline systems in the Gulf of America. At the future release site, another operator's pipeline, using a collet fitting, which overlayed the MPOG pipeline, was discovered with significant loss of cover and support.[10] Over 7,125 feet of the MPOG pipeline was laterally displaced up to 3,000 feet, and the area near MP 69 was designated a mud flow area.[11] Other components of the right-of-way for the MPOG pipeline were designated as being in a "Major Displacement Area."[12] As-built alignment sheets for the MPOG system dated to 2005 note that MP 69 contains mud flow areas, multiple previous mudflows, and scans of possible exposed pipe.[13] Panther used the CGF to repair the MPOG pipeline, which suffered pinhole leaks on the topside in contact with the other pipeline. Multiple hurricanes impacted the Gulf of America between 2004 and 2023.

After the release, Panther acknowledged that a number of geotechnical integrity threats, including seabed scour and erosion, sediment liquefication, mudslides, and seabed motion can impact pipeline operations in the Gulf of America.[14]

When the CGF was excavated following the release in November 2023, divers noted scratch marks on the pipe where it had been inserted into the collet fitting, indicating possible lateral stresses which resulted in the fitting teeth gouging the pipeline. A third-party inspection of the excavated CGF discovered significant damage to the teeth on the fitting connector where "longitudinal scoring damage" had "removed material and deformed the teeth."[15] When the CGF was excavated, the pipeline appears to have been inserted only 9 inches into the CGF, which suggests longitudinal movement of the pipeline within the connector of 15 to 24 inches, and even larger movement of the pipeline writ large.[16] Following the release, Panther acknowledged that geotechnical forces and external loads, including possible loose soil slopes and mudslides during a winter storm, likely contributed to the CGF's failure.[17]

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[8] *WPR24FR001: Materials Laboratory Factual Report*, p. 3.
[9] *WPR24FR001: Materials Laboratory Factual Report*, p. 3.
[10] *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 12 (citing "MPOG Significant Events & History Timeline").
[11] *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 13.
[12] *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 13 (citing "As-found MPOG Pipeline Displacement by 2004 Hurricane Ivan").
[13] "Combined Alignment Sheets," p. 14.
[14] *PLD-24-FR-001: Supplemental Submission of Third Coast Infrastructure, LLC*, p. 33-36.
[15] *Oil State Industries, Inc. Houston Operations: Inspection Report 18in Class 900 Collet Grip Flange NTSB No. PLD24FR001*, p. 35.
[16] *WPR24FR001: Materials Laboratory Factual Report*, p. 4; PLD-24-FR-001: *Supplemental Submission of Third Coast Infrastructure, LLC*, p. 38.
[17] *PLD-24-FR-001: Supplemental Submission of Third Coast Infrastructure, LLC*, p. 1, 48.

Foreseeable storm-driven and geotechnical external loads caused seabed instability and pipeline displacement that were not mitigated through expansion, flexibility, restraint, or support measures. Panther failed to anticipate these external loads, including expansion and contraction flexibility, in using the CGF, leaving the system in a configuration that was unable to accommodate the anticipated external loads at the installation location.

Thus, Panther failed to provide for anticipated external loads in designing its pipeline system in accordance with 49 CFR § 195.110(a).

2. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . . .

(e) What are the risk factors for establishing an assessment schedule (for both the baseline and continual integrity assessments)?

(1) An operator must establish an integrity assessment schedule that prioritizes pipeline segments for assessment (see paragraphs (d)(1) and (j)(3) of this section). An operator must base the assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment. The factors an operator must consider include, but are not limited to:

(i) . . . .

(iii) Leak history, repair history and cathodic protection history;

(iv) . . . .

(vii) Local environmental factors that could affect the pipeline (e.g., seismicity, corrosivity of soil, subsidence, climatic);

(viii) geo-technical hazards; and

(ix) Physical support of the segment such as by a cable suspension bridge.

Panther failed to base its integrity management (IM) assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment in accordance with § 195.452(e)(1). Specifically, Panther failed to adequately identify or evaluate long-standing geo-technical hazards that affected the MPOG pipeline system when establishing its integrity assessment schedule.

Panther was aware of geotechnical threats to the MPOG pipeline since at least 2004. Following Hurricane Ivan, Panther performed an inspection of the pipeline that revealed significant lateral displacement and suspended spans of the pipeline in the area where the failure occurred.[18] As-built alignment maps produced in August 2005 for post-Hurricane Ivan repairs show significant areas of exposed pipeline and mudflows over or near the pipeline, incorporating historical mudflow data from surveys conducted in 1995, 1996, and 2002.[19] Other lateral displacement on

[18] *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 13 (citing "As-found MPOG Pipeline Displacement by 2004 Hurricane Ivan").
[19] "Combined Alignment Sheets," p. 14.

the MPOG system occurred following Hurricane Katrina.[20] The 2022 hydrographic survey also showed irregular seabeds, steep slopes, and potential unsupported spans along the pipeline's route, including near MP 69.[21]

Despite this long-standing and repeatedly documented evidence of geotechnical risk, Panther failed to incorporate these conditions into its integrity management assessment schedule or to adjust its integrity assessment schedule to reflect the elevated risk posed by recurring geotechnical hazards. Panther's in-line inspection (ILI) assessment schedule prior to the release did not include tools which could address any geotechnical risk factors.[22] As a result, Panther's integrity assessment schedule did not account for known threats that directly affected the structural integrity and stability of the pipeline segment.

Therefore, Panther failed to base its integrity assessment schedule on all risk factors that reflect the risk conditions on the pipeline segment in accordance with § 195.452(e)(1).

3. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . . .

(f) What are the elements of an integrity management program? An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:

(1) . . . .

(3) An analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure (see paragraph (g) of this section);

Panther failed to include in its written integrity management program an information analysis that integrates all available integrity-related data for the pipeline and the consequences of a failure in accordance with § 195.452(f)(3). Specifically, Panther did not synthesize all available data, including prior displacement history, seabed and crossing conditions, hydrographic and IM survey data, and ILI and CGF-engagement results into its integrity management program relevant to the MP 69 segment.

Panther possessed substantial information indicating long-term, geohazard-driven instability at MP 69, including geotechnical events, storm-induced seabed movement, soft soils, and mudslide

[20] "MPOG-PHMSA-000053-MPOG-PHMSA-000055," p. 2; Combined PHMSA Requested Items, p. 115-116.
[21] "2022 Hydrographic Survey Sheets 1-17-R-Rel," p. 1; "2022 Hydrographic Survey Sheet 1 of 15 R-Rel."
[22] *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 20-22.

susceptibility, all of which posed risks to the MPOG pipeline in the Main Pass area.[23] This included historical storm-related displacement and repair history documented in alignment sheets, field layouts, and mudflow corridor mapping at and near MP 69.[24] Panther also possessed information demonstrating uneven and evolving seabed geometry, including pipeline exposure, loss of support, and possible pipeline suspensions identified through hydrographic surveys, as well as post-installation evidence of longitudinal pipeline movement relative to prior as-built configurations.[25]

Panther did not integrate any of this available data into an information analysis capable of identifying geohazards and displacement-related loading as credible threats to the MP 69 segment. Panther's IM documentation reflects discrete records and post-event analyses, but no evaluation synthesizing data associated with displacement history, seabed instability, survey findings, and mechanical connector performance into its IM program and associated with the MP 69 segment.[26]

As a result, Panther lacked a valid analytical basis for its integrity management program to manage geohazard-related threats on the MPOG system. Without a complete information analysis under § 195.452(f)(3), Panther was unable to determine and document criteria for remedial actions necessary to address integrity issues posed by geotechnical instability and displacement-related loading, as required by § 195.452(f)(4), or to identify and implement appropriate preventive and mitigative measures to protect the affected high consequence area (HCA), as required by § 195.452(f)(6).

Panther's failure to integrate all available data and change its integrity management program accordingly left the MP 69 segment managed under assumptions that did not reflect actual site conditions in the HCA.

Therefore, Panther failed to include in its written integrity management program an information analysis that integrates all available integrity-related data for the pipeline and the consequences of a failure in accordance with § 195.452(f)(3).

4. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . . .

(f) What are the elements of an integrity management program? An integrity management program begins with the initial framework. An operator must continually change the program to reflect operating experience, conclusions drawn from results of the integrity

[23] *PLD-24-FR-001: Supplemental Submission of Third Coast Infrastructure, LLC*, p. 1, 48; *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 20-22.
[24] *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 13 (citing "As-found MPOG Pipeline Displacement by 2004 Hurricane Ivan"); "Combined Alignment Sheets," p. 14;
[25] "2022 Hydrographic Survey Sheets 1-17-R-Rel", p. 1; "2022 Hydrographic Survey Sheet 1 of 15 R-Rel."; "MPOG-PHMSA-000053-MPOG-PHMSA-000055," p. 2.
[26] *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 20-22; "Combined Old ILI Reports."; *Liquid Integrity Management Plan* (rev. 3, 4/21/2023), Sec. 9.2.

assessments, and other maintenance and surveillance data, and evaluation of consequences of a failure on the high consequence area. An operator must include, at minimum, each of the following elements in its written integrity management program:

> **(1) . . . .**
>
> **(5) A continual process of assessment and evaluation to maintain a pipeline's integrity (see paragraph (j) of this section);**
>
> **(j) What is a continual process of evaluation and assessment to maintain a pipeline's integrity?**
>
> **(1) . . . .**
>
> **(2) Verifying covered segments. An operator must verify the risk factors used in identifying pipeline segments that could affect a high consequence area on at least an annual basis not to exceed 15 months (Appendix C of this part provides additional guidance on factors that can influence whether a pipeline segment could affect a high consequence area). If a change in circumstance indicates that the prior consideration of a risk factor is no longer valid or that an operator should consider new risk factors, an operator must perform a new integrity analysis and evaluation to establish the endpoints of any previously identified covered segments. The integrity analysis and evaluation must include consideration of the results of any baseline and periodic integrity assessments (see paragraphs (b), (c), (d), and (e) of this section), information analyses (see paragraph (g) of this section), and decisions about remediation and preventive and mitigative actions (see paragraphs (h) and (i) of this section). An operator must complete the first annual verification under this paragraph no later than July 1, 2021.**

Panther failed to perform a continual assessment and evaluation process to maintain its pipeline's integrity in accordance with § 195.452(f)(5). Specifically, Panther failed to perform new integrity analyses or evaluations following changes in circumstances that identified new and elevated risk factors for the MPOG pipeline covered segments.

As-found examinations of the CGF at MP 69, including ultrasonic testing (UT) wall-thickness measurements and as-received geometry, revealed non-uniform wall loss, localized deformation, and misalignment consistent with long-term mechanical loading rather than a single, instantaneous failure mechanism.[27] These conditions reflect progressive displacement and sustained load transfer into the mechanical connector over time. In addition, integrity management records and survey data identified loss of support, exposed pipeline segments, and areas of possible suspension along the MPOG route, including in the vicinity of the CGF location.[28] The 2022 hydrographic survey showed potential deep troughs and unstable slopes in the seabed along the route.[29]

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[27] *WPR24FR001: Materials Laboratory Factual Report*, p. 3-4; 9-10.

[28] *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 13-19;

[29] "2022 Hydrographic Survey Sheets 1-17-R-Rel", p. 1; "2022 Hydrographic Survey Sheet 1 of 15 R-Rel."

Despite this evidence of ongoing pipeline movement, seabed instability, and progressive degradation of the CGF installation, Panther did not conduct any targeted reassessment, updated integrity analysis, or follow-up evaluation to address the newly identified geohazard and mechanical loading threats.[30] Panther did not reevaluate the suitability of the CGF under these evolving conditions, reassess interacting threats, or modify its integrity assessment strategy to reflect the observed changes in circumstances.

By failing to act on this information and failing to perform additional integrity evaluations when conditions indicating new risk factors were identified, Panther did not maintain a continual assessment and evaluation process capable of identifying and mitigating emerging threats to pipeline integrity.

Therefore, Panther failed to perform a continual assessment and evaluation process to maintain its pipeline's integrity in accordance with § 195.452(f)(5).

5. § 195.452 Pipeline integrity management in high consequence areas.

(a) . . . .

(i) *What preventive and mitigative measures must an operator take to protect the high consequence area?*

(1) . . . .

(3) *Leak detection.* An operator must have a means to detect leaks on its pipeline system. An operator must evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. An operator's evaluation must, at least, consider, the following factors—length and size of the pipeline, type of product carried, the pipeline's proximity to the high consequence area, the swiftness of leak detection, location of nearest response personnel, leak history, and risk assessment results.

Panther failed to evaluate the capability of its leak detection means and modify, as necessary, to protect high consequence areas in accordance with § 195.452(i)(3). Specifically, Panther's Integrity Management Plan and Operations & Maintenance Manual *Hazardous Liquids 195* (rev. 4, 10/2022) ("O&M Manual") failed to include an evaluation of its leak detection system.

PHMSA requested records demonstrating that Panther had evaluated the capability of its leak detection means to protect the HCA. Panther produced no records of any such evaluation conducted prior to the accident, even though the MPOG pipeline system and release location were in an HCA.[31]

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[30] *PLD-24-FR-001: Pipeline Operations/Integrity Management*, p. 13-19, 20-21, 28-29.
[31] "CRM Audit Request No. 44 Response."

At the time of the release, Panther's Integrity Management program indicated in several locations that leak detection systems would be evaluated for the capability to protect an HCA, including accounting for swiftness, but records associated with implementation were not available.[32] In addition, Panther's O&M Manual did not require or document any evaluation of the effectiveness of the leak detection methods actually relied upon for the MPOG pipeline. Instead, Section 4.6, "Leak Detection to Include CPM," only provided for the evaluation of proposed or future CPM systems, referenced the code requirements, and indicated that over-shorts balancing would be used for leak detection. Section 4.6 did not establish any process, criteria, performance thresholds, or acceptance metrics for the capability of the over-shorts or imbalance method, nor did it require periodic review, validation, or modification of that method to ensure adequate protection of HCAs.

Furthermore, Panther's over-shorts or imbalance method was not supported by automated alarming on imbalance, sensitivity thresholds, or validated response criteria. Instead, it relied on controller interpretation of flow, pressure, over and short values, and imbalance changes that would require action.[33] Control-room records indicate that, during the release, the SCADA system did not generate a definitive alarm or alert that would have prompted immediate shutdown or escalation based on imbalance.[34] Panther's imbalance tracking and data entry processes, separate from the SCADA system, also experienced an intermittent outage during the release, further degrading the effectiveness of the over-shorts or imbalancing method as a leak detection tool.[35]

Therefore, Panther failed to evaluate the capability of its leak detection means and modify, as necessary, to protect high consequence areas in accordance with § 195.452(i)(3).

6. § 195.402 Procedural manual for operations, maintenance, and emergencies.

(a) . . . .

(d) Abnormal operation. The manual required by paragraph (a) of this section must include procedures for the following to provide safety when operating design limits have been exceeded:

(1) Responding to, investigating, and correcting the cause of:

(i). . . .

(ii) Increase or decrease in pressure or flow rate outside normal operating limits.

(iii) . . . .

(v) Any other malfunction of a component, deviation from normal operation, or personnel error which could cause a hazard to persons or property.

Panther's O&M Manual failed to include procedures for responding to, investigating, and correcting the cause of an increase or decrease in pressure or flow rate outside normal operating

[32] *Liquid Integrity Management Plan* (rev. 3, 4/21/2023), Sec. 7.2.
[33] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 18-19, 30-31.
[34] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 31.
[35] "Combined Control Room Records of the Event - SCADA Data," p. 3; "LMS OCC Daily Log MPOG-000001-MPOG-000014_2023-11-18-Redacted-Rel," p. 1.

limits or the malfunction of a component in accordance with § 195.402(d)(1)(ii) and (v). Specifically, the O&M Manual failed to specify controller actions in response to a zero-flow indication or to a specific imbalance magnitude such as those that occurred at MP 69 during the release.

Panther's O&M Manual failed to specify an imbalance level at which specific response steps were required. O&M Manual Sections 10.1 and 10.1.1 provide examples and definitions of abnormal operating conditions (AOCs), but did not refer to specific imbalance levels or zero-flow indication. Instead, the O&M Manual referred only to "unexplained deviation in pressure or flow, including unexplained line imbalance alarms."[36]

On the night of the release, the controller indicated that imbalance accumulations continued to grow over the course of the night,[37] but there was no defined imbalance magnitude at which point the controller was required by procedure to take any specific action. Instead, response actions were discretionary and repetitive, allowing the release to continue.[38]

Similarly, the lack of specified response requirements to the zero-flow indication meant that, once automatic valves failed to close, the controller had no procedurally required next step and the release continued.[39] The O&M Manual identified as an AOC a "valve that does not respond to a command, AND that results in system limits being exceeded." However, zero-flow was not identified as a design or operating limit requiring action if exceeded, and the failure of the valve to actuate did not itself cause a system limit exceedance; rather, the system remained flowing in an abnormal and unsafe configuration without a required procedural response.

PHMSA's review of Panther's records confirmed that the O&M Manual in place prior to the incident did not contain procedures establishing mandatory response actions for imbalance growth, zero-flow conditions, or failed valve actuation independent of a pressure exceedance.

Therefore, Panther's O&M Manual failed to include procedures for responding to, investigating, and correcting the cause of an increase or decrease in pressure or flow rate outside normal operating limits or the malfunction of a component in accordance with § 195.402(d)(1)(ii).

7. § 195.402 Procedural manual for operations, maintenance, and emergencies.

(a) . . . .

(e) Emergencies. The manual required by paragraph (a) of this section must include procedures for the following to provide safety when an emergency condition occurs:

[36] Based on PHMSA's investigation, line imbalance alarms were not used on the MPOG system at the time of the accident. This list is meant to be exhaustive: Section 10.1.1.1 states that "All Abnormal Operations shall fall into one of the Identified Abnormal Operations Listed Below."

[37] Responses to NTSB Information Request, p. 6.

[38] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 9-15; "Combined Control Room Records of the Event - SCADA Data," p. 3.

[39] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 9-15; "Combined Control Room Records of the Event - SCADA Data," p. 3.

(1) . . . .

(4) Taking necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released hazardous liquid or carbon dioxide to life, property, or the environment. Each operator must also develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture, as defined in § 195.2, is an actual rupture event or non-rupture event. These procedures must, at a minimum, specify the sources of information, operational factors, and other criteria that operator personnel use to evaluate a notification of potential rupture, as defined at § 195.2. For operators installing valves in accordance with § 195.258(c), § 195.258(d), or that are subject to the requirements in § 195.418, those procedures should provide for rupture identification as soon as practicable.

Panther failed to have emergency procedures to take necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released hazardous liquid or carbon dioxide to life, property, or the environment, in accordance with § 195.402(e)(4). Specifically, Panther's O&M Manual failed to specify the types of situations, operational indicators, or objective evidence that would lead personnel to recognize that an emergency had occurred and take required emergency actions.

Panther's O&M Manual, Section 11.0, "Emergency Operations," stated:

All Third Coast employees shall follow this procedure when the following conditions have been met or will be met on DOT 195 jurisdictional pipelines and facilities or when the regulatory status is unknown:
1. Unintentional release of any product; or
2. Death or personal injury requiring hospitalization; or
3. Fire or explosion not intentionally set by Third Coast; or
4. Estimated property damage exceeding $50,000; or
5. Pollution of any water body; or
6. Events deemed significant by Third Coast.

The phrase "Events deemed significant by Third Coast" was not clarified until later in the procedures, in Section 11.2.5, "Determine Whether Accident is Reportable," which explained as follows:

Failure that is significant in the judgment of the Third Coast even though it did not meet the above criteria. Events are significant when the public health and safety are believed to be in immediate

> *danger such as, when the media is present, when evacuations occur, or when public transportation arteries are impacted. or examples provided to employees.*

This clarification described significance only in hindsight-based or externally observable terms—such as media presence, evacuations, or impacts to public transportation—rather than operational indicators available to controllers during an unfolding event.

Meanwhile, Section 11.1 "Receiving, Identifying and Classifying Emergencies" in the definitions sections stated:

> ***Emergency*** *– is defined as an unforeseen event which calls for immediate action, that:*
> *1. Is immediately threatening to life, health, property or environment.*
> *2. Has a high probability of escalating to cause immediate danger to life, health, property or environment.*

None of these explanations provide objective, operationally measurable criteria—such as SCADA indications, imbalance growth, zero-flow conditions with incoming supply, minimum pressure thresholds, or failed valve actuation, whether as commanded by a controller or via programmable logic controller (PLC) logic—that would guide personnel in determining when an emergency existed or when emergency shutdown, valve isolation, or pressure reduction was required.

As a result, employees were required to independently interpret whether an emergency existed based on subjective judgment rather than prescribed criteria. This lack of specificity resulted in inconsistent operational responses, delayed escalation, and continued operation while abnormal conditions or emergency conditions persisted.[40]

Therefore, Panther failed to have emergency procedures to take necessary actions, including but not limited to, emergency shutdown, valve shut-off, or pressure reduction, in any section of the operator's pipeline system, to minimize hazards of released hazardous liquid or carbon dioxide to life, property, or the environment, in accordance with § 195.402(e)(4).

8. § 195.446 Control room management.

(a). . . .

(b) Roles and responsibilities. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

(1) . . . .

[40] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 9-15; "Combined Control Room Records of the Event - SCADA Data," p. 3.

(2) A controller's role when an abnormal operating condition is detected, even if the controller is not the first to detect the condition, including the controller's responsibility to take specific actions and to communicate with others;

Panther failed to define a controller’s role when an abnormal operating condition is detected, including the controller’s responsibility to take specific actions and to communicate with others, in accordance with § 195.446(b)(2). Specifically, Panther’s *CRM-000: Control Room Management* (rev. 15, 6/21/23) (“CRM Plan”) failed to identify as abnormal operating conditions any specific level of imbalance amount, equipment malfunctions that impact operations, or zero-flow conditions at MP 69 during the release, and failed to define required specific controller actions and communication requirements when such conditions occurred.

Panther’s CRM Plan Section 2.6.0 failed to indicate any specific imbalance level, equipment malfunction, or zero-flow condition that would constitute an abnormal operating condition requiring defined controller action. The CRM Plan relied on general descriptions of abnormal operations and did not tie those descriptions to objective, operational indicators observable by controllers in real time. As a result, conditions that occurred during the release, including growing imbalance volumes and zero-flow indications, were not procedurally defined as AOCs within the CRM framework. The specific actions required to be taken were not clear, and while the controller during the evening of the accident did communicate with their supervisor regarding the imbalance, the communication did not reoccur when zero flow occurred at MP 69.[41]

Similarly, Panther’s CRM Plan Section 2.6.2, “OCC Supervisor Responsibilities During Abnormal Operating Conditions,” failed to identify specific procedures or processes such as established decision logic, escalation criteria, or required information exchange to determine abnormal operations in the event of zero-flow at MP 69, imbalance differences, or other conditions such as minimum pressure at MP 225. The CRM Plan does not identify key information that should be collected or asked for from a controller when a controller makes a call about unusual conditions on imbalance, such as that which occurred on the night of the failure. During the release, this lack of definition resulted in informal, inconsistent communications and reliance on subjective judgment rather than prescribed and specific controller and supervisor actions.[42]

Panther’s O&M Manual similarly provided insufficient guidance to controllers. Panther’s O&M Manual Section 10.3.2, item 4 stated that if “a logical reason for deviations cannot be determined, Control Room Operations should arrange for an orderly shutdown of the pipeline.” However, the procedure failed to indicate if shutdown in those circumstances was mandatory, leaving it to the controller’s discretion. In addition, the procedure provided no actionable threshold for when a logical reason for a deviation had been determined, undermining the ability of controllers to know when to act.

[41] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 9-15; “Combined Control Room Records of the Event - SCADA Data,” p. 3.

[42] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 9-15; “Combined Control Room Records of the Event - SCADA Data,” p. 3.

For zero-flow conditions specifically, Panther's O&M Manual Section 10.3.5 "Remotely Operated (unmanned) Pump Stations,"[43] included the following steps in relevant part:

> *2. Sudden, Unexplained Increase or Decrease in Flow Rate*
> *a. Increases in flow rates that are not caused by Pipeline Control-initiated changes in operations shall be investigated.*
> *b. A sudden increase in flow rate could indicate a break in the pipeline, particularly if accompanied by a sudden decrease in pressure. If both should occur simultaneously and the Pipeline Controller cannot readily determine the cause, implement OM-105 Section 11 Emergency Response Procedures.*
> *c. If an increase in flow rate without a corresponding decrease in pressure is observed, the Pipeline Controller shall notify the responsible technician, the person on call, or the appropriate supervisor and request on-site investigation.*
> *d. The Pipeline Controller shall monitor the pipeline segment affected by the increased flow rate until the cause is determined.*
> *e. An abrupt decrease in flow rate could indicate an unauthorized valve closure, a plugged strainer, etc. The Pipeline Controller shall investigate any suspicious decreases in flow rate that are not the result of a Pipeline Controller-initiated change in operations.*
> *f. If the Pipeline Controller cannot readily determine the cause of the decreased flow rate, the Pipeline Controller shall notify the responsible technician or person on call in the affected area and request an on-site investigation.*
> *g. The Pipeline Controller shall monitor the affected pipeline segment until the cause of the decreased flow rate is determined.*
> *h. The Pipeline Controller shall document the occurrence.*

Aside from its failure to notify the controller that a zero-flow indication could be the result of a leak, the procedure contained no steps for the controller after the initiation of an onsite investigation, such as defining the controller's role in the event that the investigation failed to identify an operational cause of the leak indications or requiring escalation or shutdown. In cases, such as the night of the release, where an onsite investigation reveals nothing wrong, the procedure offers no further guidance. As a result, on the night of the release, once on-site investigation did not identify a cause, the controller had no defined procedural role or next step, and the abnormal condition persisted.[44]

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[43] While the release did not involve a pump station, this section of the O&M Manual is one of the places in Panther's procedures which provided partial guidance to controllers.

[44] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 9-15; "Combined Control Room Records of the Event - SCADA Data," p. 3.

For imbalance levels, Panther's O&M Manual in Section 10.3.4 "Line Imbalance and/or Product Loss – Procedure for Control Room Operations" stated in relevant part:

> *Line Imbalance and/or Product loss is usually detected by routine over/short determinations. Regularly the line may indicate a small loss and then a reasonable gain to offset the loss. These fluctuations are normally attributed to pressure deviations affecting "line pack" or caused by minor metering variances. Consistent losses of a small magnitude can possibly be attributed to meter variance or a small line leak. The Measurement Department should be informed of these situations or Control Room Operations may, in good judgment, shut down the line to monitor the pressure to eliminate the suspicion of a leak.*

The guidance that a controller "may, in good judgment, shut down a line" is not sufficient guidance to personnel charged with making such a decision. On the night of the release, the controller repeatedly advocated for shutdown but lacked objective criteria to support that decision when challenged by other personnel.[45] As a result, the imbalances grew and the release continued.

Similarly, in Section 10.3.4, item 2, the O&M Manual stated in relevant part:

> *However, a sudden sizable imbalance on the loss side should alert Control Room Operations to the potential of a leak. If any part of the system is not balancing after making a volume or an instantaneous rate injected vs. delivered calculation, the following steps should be initiated:*
> *a. Notify on call personnel and/or Supervision as appropriate.*
> *b. Check pressure and flow data at all points along pipeline where (line segment) of product loss.*
> *c. Meters registering to and from the system should be checked against other Company or Customer meters up and/or downstream, if possible.*
> *d. Available flow or pressure charts or trends should be examined for any sudden or unusual changes since the last satisfactory balance check was made.*
> *e. Check all valve alignments to ensure that an unintended change has not occurred.*
> *f. If shortage cannot be explained, arrange for orderly shutdown of the line to hold the pressure above vapor pressure at all points. If a leak is suspected, treat as an emergency condition and proceed with appropriate procedures from Section 11."*

[45] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 9-15; "Combined Control Room Records of the Event - SCADA Data," p. 3.

g. Close all applicable remotely operable mainline valves to identify/isolate the affected line segment and minimize loss of product.
h. The line should not be restarted until the problem has been identified and corrected and authorization given by field operations and integrity management.
i. Document all unexplained line imbalance or product loss in Control Room log, and/or by separate report.
j. If the cause of the shortage condition has been identified and corrected, Control Room Operations should monitor the operation for the next hour.

Similarly to the rest of Section 10.3.4, this section did not give sufficient guidance to personnel. The procedure defined neither a "sizeable" imbalance nor a "sudden" imbalance: personnel were left to their own devices when determining whether to follow the steps described. For example, a gradual but continuous buildup of imbalance, such as occurred during the event, was not clearly captured by the procedure and did not trigger mandatory action. This lack of defined authority resulted in unresolved disagreement and delayed decision-making during the event.[46]

Therefore, Panther failed to define a controller's role when an abnormal operating condition is detected, including the controller's responsibility to take specific actions and to communicate with others, in accordance with § 195.446(b)(2).

9. § 195.446 Control room management.

(a). . . .

(b) Roles and responsibilities. Each operator must define the roles and responsibilities of a controller during normal, abnormal, and emergency operating conditions. To provide for a controller's prompt and appropriate response to operating conditions, an operator must define each of the following:

(1) . . . .

(3) A controller's role during an emergency, even if the controller is not the first to detect the emergency, including the controller's responsibility to take specific actions and communicate with others.

Panther failed to define a controller's role in an emergency, including the controller's responsibility to take specific actions and communicate with others, in accordance with § 195.446(b)(3). Specifically, Panther's CRM Plan failed to adequately define the controller's obligation to promptly and appropriately respond to emergency conditions, including required actions, authority, and communications, despite Panther's emergency planning assumptions requiring rapid detection and shutdown.

[46] "Combined Control Room Records of the Event - SCADA Data," p. 3.

Panther's CRM Plan, Section 2.7.1 "Controller Responsibilities During Emergency Operating Conditions" states in relevant part that:

> *In addition to their responsibilities during normal operations, during emergency operating conditions, the responsibilities of Controllers may include but are not limited to the following activities:*
> *• When an emergency condition is identified, the Controller has operational authority to shut down, or instruct the applicable field personnel to shut down the affected pipeline and stop any work that could compound the incident/accident*
> *• Perform appropriate actions, per the Lighthouse Midstream Services Operations and Maintenance (O&M) OM-195 Manual Section 11 (Emergency Operations) for Liquids and OM-192 Section 11 (Emergency Operations) for Gas; or as documented within external O&M manuals of entities that Lighthouse Midstream Services operates on their behalf*
> *• After contacting field personnel and initiating an emergency response, the Controller should contact their OCC Supervisor and/or Local Field Supervisor if they have not already been notified.*

This section inadequately describes the responsibilities of controllers in the event of an emergency. The procedure describes what controllers are capable of doing, not what they are required to do, and does not establish mandatory decision points, sequencing, or timing expectations.

This deficiency is significant because Panther's *Regional Oil Spill Response Plan, High Point Gas Gathering, L.L.C., Gulf of Mexico Operations, BSEE I.D. #03255* (Version 1-0) states that "The pipeline system detection time and the shutdown response time for an uncontrolled blowout has been estimated to be 0.25 hours." That assumption necessarily requires immediate recognition of emergency conditions by controllers, prompt execution of shutdown or isolation actions, and clear authority to act without delay. Panther's CRM Plan Section 2.7.1 does not communicate this expectation to controllers, does not reference the 0.25-hour assumption, and does not require controllers to act within any defined timeframe during an emergency. Instead, Section 2.7.1 refers controllers to other manuals and suggests notification and consultation after actions are initiated, without defining when emergency responsibility must be exercised or what constitutes unacceptable delay.

Therefore, Panther failed to define a controller's role in an emergency, including the controller's responsibility to take specific actions and communicate with others, in accordance with § 195.446(b)(3).

10. § 195.446 Control room management.

(a). . . .

(h) *Training.* Each operator must establish a controller training program and review the training program content to identify potential improvements at least once each calendar year, but at intervals not to exceed 15 months. An operator's program must provide for training each controller to carry out the roles and responsibilities defined by the operator. In addition, the training program must include the following elements:

(1) Responding to abnormal operating conditions likely to occur simultaneously or in sequence;

Panther failed to establish a controller training program that provided for training each controller to carry out the roles and responsibilities defined by the operator in accordance with § 195.446(h). Specifically, Panther's pipeline controller training program failed to inform controllers of key information and responsibilities needed for executing their roles.

Panther's controller training program failed to communicate that a zero-flow condition at MP 69 may be an indication of a leak and failed to instruct controllers on whether and when immediate shutdown or escalation should be performed in response to a zero-flow indication at MP 69. PHMSA did not identify any controller training materials, lesson plans, presentations, or curriculum content instructing controllers that a zero-flow indication at MP 69, particularly when occurring outside of a controller-initiated operational change, may represent a leak condition requiring escalation or shutdown.

In addition, Panther's training program failed to train controllers on responding to abnormal operating conditions likely to occur simultaneously or in sequence, such as gradual line imbalance, zero-flow indications at MP 69, and automatic valve failures. During the release, several abnormal operating conditions occurred simultaneously or in sequence, including the zero-flow indication at MP 69, a gradual building of line imbalance, and the failure of automatic valves to close.

Lastly, Panther failed to train controllers on emergency response in line with its own emergency response expectations. Panther's *Regional Oil Spill Response Plan, High Point Gas Gathering, L.L.C., Gulf of Mexico Operations, BSEE I.D. #03255* (Version 1-0) states that "The pipeline system detection time and the shutdown response time for an uncontrolled blowout has been estimated to be 0.25 hours." However, PHMSA did not identify any controller training materials incorporating this response-time expectation, nor any drills, simulations, or performance benchmarks designed to ensure controllers could recognize emergencies and execute shutdown actions within that timeframe. The absence of training tied to Panther's own emergency response assumptions demonstrates that controllers were not trained to meet the operator's stated emergency performance expectations.

These failures demonstrate that Panther's controller training program did not equip controllers with the knowledge, expectations, or decision-making framework necessary to adequately and promptly recognize and respond to the release. These omissions, taken together, inhibited the controller's ability to adequately and promptly recognize and respond to the release, contributing to the extended duration between the initial abnormal indications and shutdown of the pipeline.

Thus, Panther failed to establish a controller training program that provided for training each controller to carry out the roles and responsibilities defined by the operator in accordance with § 195.446(h).

11. § 195.420 Valve maintenance.
(a) Each operator shall maintain each valve that is necessary for the safe operation of its pipeline systems in good working order at all times.

Panther failed to maintain each valve necessary for the safe operation of its pipeline systems in good working order at all times in accordance with § 195.420(a). Specifically, on the date of the failure, mainline valves 301, 303, and 305 at MP 69 failed to close by automatic operation and failed to close when commanded from the control room.

At approximately 12:29 am on November 16, 2023, the PLC and control room settings required automatic closure of the MP 69 valves in response to the zero-flow indication.[47] However, valves 301, 303, and 305 did not close as designed, indicating that the valves were not capable of performing their safety function when required.[48] In addition, following the failure of automatic closure, the controller issued SCADA commands directing the MP 69 valves to close, but the valves failed to respond to commands issued by the controller.[49]

Valve maintenance, inspection, and operability expectations require that valves necessary for safe operation function on demand, including under emergency conditions. The failure of multiple valves at the same location to respond to both automatic logic and manual SCADA commands demonstrates that the valves were not maintained in good working order at all times.

Therefore, Panther failed to maintain each valve necessary for the safe operation of its pipeline systems in good working order at all times in accordance with § 195.420(a).

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[47] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 14.
[48] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 14; "Combined Control Room Records of the Event - SCADA Data," p. 3.
[49] *PLD-24-FR-001: Human Performance, System Safety and SCADA*, p. 14; "LMS OCC Daily Log MPOG-000001-MPOG-000014_2023-11-18-Redacted-Rel," p. 2.

Proposed Civil Penalty

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to exceed $272,926 per violation per day the violation persists, up to a maximum of $2,729,245 for a related series of violations. For violation occurring on or after December 28, 2023 and before December 30, 2024, the maximum penalty may not exceed $266,015 per violation per day the violation persists, up to a maximum of $2,660,135 for a related series of violations. For violation occurring on or after January 6, 2023 and before December 28, 2023, the maximum penalty may not exceed $257,664 per violation per day the violation persists, up to a maximum of $2,576,627 for a related series of violations. For violation occurring on or after March 21, 2022 and before January 6, 2023, the maximum penalty may not exceed $239,142 per violation per day the violation persists, up to a maximum of $2,391,412 for a related series of violations. For violation occurring on or after May 3, 2021 and before March 21, 2022, the maximum penalty may not exceed $225,134 per violation per day the violation persists, up to a maximum of $2,251,334 for a related series of violations. For violation occurring on or after January 11, 2021 and before May 3, 2021, the maximum penalty may not exceed $222,504 per violation per day the violation persists, up to a maximum of $2,225,034 for a related series of violations. For violation occurring on or after July 31, 2019 and before January 11, 2021, the maximum penalty may not exceed $218,647 per violation per day the violation persists, up to a maximum of $2,186,465 for a related series of violations.

We have reviewed the circumstances and supporting documentation involved for the above probable violations and recommend that you be preliminarily assessed a civil penalty of $ 9,622,054 as follows:

Item number	PENALTY
2	$ 2,576,627
5	$ 2,234,400
6	$ 2,234,400
11	$ 2,576,627

Proposed Compliance Order
With respect to Item 1 pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Panther, Operating LLC. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Warning Items
With respect to Items 3, 4, 7, 8, 9, and 10, we have reviewed the circumstances and supporting documents involved in this case and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time.

Response to this Notice
Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Enforcement Proceedings*. Please refer to this document and note the response options. All material you submit in response to this enforcement action may be made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. §552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. § 552(b).

Following your receipt of this Notice, you have 30 days to respond as described in the enclosed *Response Options*. If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order. If you are responding to this Notice, we propose that you submit your correspondence to my office within 30 days from receipt of this Notice. The Region Director may extend the period for responding upon a written request timely submitted demonstrating good cause for an extension.

In your correspondence on this matter, please refer to **CPF 4-2025-012-NOPV** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

BRYAN JEFFERY LETHCOE

Digitally signed by BRYAN JEFFERY LETHCOE
Date: 2025.12.31 08:15:32 -06'00'

Bryan Lethcoe
Director, Southwest Region, Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration

Enclosures: *Proposed Compliance Order*
Response Options for Pipeline Operators in Enforcement Proceedings

cc: Brian Nielsen, Senior Vice President and Chief Operating Officer, Third Coast Midstream, LLC, bnielsen@third-coast.com
Nicklas Pavlovsky, Manager, Pipeline Compliance, Third Coast Midstream, LLC, npavlovsky@third-coast.com

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to Panther Operating, LLC (Panther) a Compliance Order incorporating the following remedial requirements to ensure the compliance of Panther with the pipeline safety regulations:

A. In regard to Item 1 of the Notice pertaining to Panther's failure to provide for anticipated external loads in the design of its pipeline system in accordance with § 195.110(a), Panther must conduct a comprehensive technical review of the anticipated external loads acting on each component of the MPOG pipeline system. This review must explicitly address geotechnical and geological hazards, including but not limited to earth movement, loss of cover, loss of support, seabed instability, differential settlement, and other externally imposed environmental forces that are reasonably foreseeable over the operating life of the system. In performing this review, Panther must account for the conditions, risk factors, and actions identified in PHMSA Advisory Bulletin ADB-2022-01 (Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards). Based on the results of this technical review, Panther must develop and submit a remediation plan identifying all pipeline components that the review concludes cannot withstand anticipated external loads. The remediation plan must specify corrective measures, implementation timelines, and interim risk controls necessary to ensure the MPOG system is adequately designed, supported, and protected against such external loads. Panther must submit the completed technical review and remediation plan to the Director, Southwest Region, within **90** days of the receipt of the Final Order.

B. It is requested (not mandated) that Panther maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Bryan Lethcoe, Director, Southwest Region, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration. It is requested that these costs be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.