NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

VIA ELECTRONIC MAIL TO: bkent@calibermidstream.com; cmaybee@calibermidstream.com; neddy@calibermidstream.com

June 26, 2025

Bill Kent
Chief Executive Officer
Caliber Midstream Partners, LP
Caliber Spring Creek, LLC
1805 Shea Center Drive, Suite 285
Highlands Ranch, CO 80129

CPF 3-2025-001-NOPV

Dear Mr. Kent:

From April 25 through April 29, 2022, May 2 through May 4, 2022, May 9 through May 11, 2022, and July 21, 2022, 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.), inspected Caliber Spring Creek, LLC's procedures and associated records for Control Room Management (CRM), SCADA, Leak Detection, and Operations and Maintenance (O&M) relevant to the control room located in Houston, Texas.

Caliber Midstream Partners, LP (Caliber) operates multiple systems: Caliber North Dakota, Caliber Bear Den Interconnect, and Caliber Spring Creek Pipeline System (CSC). On October 29, 2019, CSC assets were monitored and controlled by a third-party control room, NuGen Automation. On October 1, 2021, NuGen Automation became part of Everline Automation (Everline). At the time of the inspection, CSC assets were operated by a third-party control room, Everline. Everline was still using some of the NuGen Automation procedures and associated records. Everline's CRM procedures and records apply to CSC.

As a result of the inspection, it is alleged that Caliber and CSC have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (CFR). The items inspected and the probable violations are:

1. § 195.402 Procedural manual for operations, maintenance, and emergencies.

> **(a) *General.* Each operator shall prepare and follow for each pipeline system a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual shall be reviewed at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes made as necessary to insure that the manual is effective. This manual shall be prepared before initial operations of a pipeline system commence, and appropriate parts shall be kept at locations where operations and maintenance activities are conducted.**

Caliber and CSC failed to follow written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies, per the requirements of § 195.402(a). Specifically, Caliber's O&M procedure, "SOP 1000-1005 Tank Overfill Inspection and Testing" (rev. 0, Mar. 16, 2022), was not followed when transmitters for Breakout Tanks 111-118 level indications were tested on September 12, 2022.

Breakout Tanks 111-118 level indications were monitored and alarmed in the Everline Third-Party control room. O&M procedure SOP 1000-1005 required that the control room be communicated with during the Initial Inspection Steps of the procedure because controllers need to know that alarms and readings received were a result of inspection and testing procedures, not actual conditions.

As a result of requested information occurring with the control room inspection, PHMSA reviewed the calibration testing records for the level indications on Breakout Tanks 111-118 occurring on September 12, 2022. Caliber and CSC failed to follow O&M procedure SOP 1000-1005 because it did not verify overfill activation by communicating with the controller, as required by procedures. Thus, controllers would not have known that alarms and readings received during the calibration testing were not actual conditions. Therefore, Caliber and CSC failed to follow written procedures, as required by § 195.402(a), when testing overfill systems on breakout tanks.

2. § 195.444 Leak detection.

> **(a) . . . .**
> **(b) *General.* A pipeline must have an effective system for detecting leaks in accordance with §§ 195.134 or 195.452, as appropriate. An operator must evaluate the capability of its leak detection system to protect the public, property, and the environment and modify it as necessary to do so. At a minimum, an operator's evaluation must consider the following factors - length and size of the pipeline, type**

of product carried, the swiftness of leak detection, location of nearest response personnel, and leak history.

Caliber failed to evaluate the capability of its system for detecting leaks on a pipeline in accordance with §§ 195.134 or 195.452, as appropriate. Specifically, Caliber did not evaluate the capability of its leak detection system to protect the public, property, and environment and to modify it as necessary to do so for the portion of the Spring Creek pipeline system (known as the Southeast Extension) constructed after October 1, 2019, per § 195.134.[1]

PHMSA received notification F-20200324-23792 on March 24, 2020, and this identified that 10.9 miles of 10" (crude oil) pipeline was added in McKenzie County, North Dakota. While work began on May 4, 2019, construction was not completed until March 2020. Because construction was not completed until March 2020, the pipeline was "constructed on or after October 1, 2019."[2] Additionally, a request was made for the starting date for the Southeast Extension, and a KMZ file[3] was submitted which showed February 27, 2020, as the date Caliber identified this pipeline being active.

During the CRM inspection, PHMSA requested information associated with the evaluation of the capability of the leak detection system relevant to the portion of the Spring Creek pipeline system constructed after October 1, 2019. No record was available to demonstrate that this evaluation of the capability of its leak detection system to protect the public, property, and environment had been performed. Information exchanged during the inspection, verbally, also supported the fact that an evaluation of the capability of the leak detection system had not been completed for the portion of the Spring Creek pipeline system constructed after October 1, 2019.

3. § 195.446 Control room management.

(a) General. This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .

(b) . . . .

(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

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[1] 49 CFR § 195.134(b)(2) states that for each pipeline constructed on or after October 1, 2019, each pipeline system must have a system for detecting leaks that complies with the requirements in § 195.444 by October 1, 2020.

[2] *See Id.*

[3] A KMZ file is a file type used in geographic information systems.

(1) Implement API RP 1165 (incorporated by reference, *see* § 195.3) whenever a SCADA system is added, expanded or replaced, unless the operator demonstrates that certain provisions of API RP 1165 are not practical for the SCADA system used;

CSC failed to provide its controllers with the information, tools, process, and procedures necessary for the controllers to carry out the roles and responsibilities the operator defined by failing to implement API RP1165 whenever a SCADA system is added, expanded, or replaced, unless the operator demonstrates that certain provisions of API RP 1165 are not practical for the SCADA system used, as required by § 195.446(c)(1). Specifically, API RP 1165, section 5, states:

> 5.3 DISPLAY RESPONSE
> Display sub-system response is a function of both hardware performance and software design. In modern SCADA systems that use client server architecture, both the host (server) and HMI computer (client) can affect the initial display call-up time and data refresh rate. Once installed, display response times should be periodically reviewed.

On October 1, 2021, NuGen Automation became part of Everline. The NuGen and ROC control rooms were officially merged to EverLine in September 2022. When control rooms are merged, software, hardware and communication changes do occur that impact data refresh rates and impact information and tools necessary for the controllers to carry out the roles and responsibilities that the operator has defined. Records did exist to indicate that API RP 1165 section 5 was confirmed for data refresh rates[4] on October 29, 2019. However, nothing provided during the inspection identified that data refresh rates were confirmed upon changes to the merged control room occurring after this date.

At the time of the inspection, while 10 seconds was reported to be the expected response time for data refresh rates, confirmation of the original design data refresh rates was not available for the current software version, hardware configuration, and control room location. Additionally, during the inspection, PHMSA asked if any provisions of API RP 1165 were "not practical" for the SCADA system used. CSC confirmed that nothing was deemed to be impractical for this inspection. Thus, CSC could not demonstrate that API RP 1165 section 5 had been implemented, as required by § 195.446(c)(1).

4. § 195.446 Control room management.

(a) General. This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .
(b) . . . .

[4] Data refresh rate is the time at which data identified in the SCADA system or Programmable Logic Controller is updated to most recent values.

(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) . . . .

(2) Conduct a point-to-point verification between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays;

CSC failed to conduct point-to-point (P2P) verifications between SCADA displays and related field equipment when field equipment is added or moved and when other changes that affect pipeline safety are made to field equipment or SCADA displays, as required by § 195.446(c)(2). CSC did not have P2P verification records for any points including that relevant to the Southeast Extension.

PHMSA received notification F-20200324-23792 on March 24, 2020, regarding the Southeast Extension. This notification identified that 10.9 miles of 10-inch, crude oil pipeline was added in McKenzie County, North Dakota. A KMZ file provided by CSC showed February 27, 2020, as the active date. The Southeast Extension added field equipment that necessitated a P2P. PHMSA requested further information for the P2P records for the Southeast Extension from CSC and no P2P records were provided.

Additionally, PHMSA requested the alarms and display confirmation and documentation for any point on the CSC system. The response indicated that CSC was unable to find original P2P documentation. CSC did not have any P2P records that demonstrated which displays were checked in the SCADA system or that confirmed the alarm setpoint values, and alarm descriptors had been part of the P2P verification. The lack of records indicate that P2P verification was not performed on any point in the system relevant to CSC.

CSC failed to conduct point-to-point verifications between SCADA displays and related field equipment when field equipment was added or moved or when other changes were made that affected pipeline safety as required by § 195.446(c)(2).

5. § 195.446 Control room management.

(a) General. This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .

(b) . . . .

(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:

(1) . . . .
(3) Test and verify an internal communication plan to provide adequate means for manual operation of the pipeline safely, at least once each calendar year, but at intervals not to exceed 15 months;

CSC failed to test and verify the internal communications plan for manual operations once per calendar year not to exceed 15 months, as required by § 195.446(c)(3). CSC did not test and verify the internal communications plan for manual operations in 2021 and 2022.

PHMSA requested the 2019-2022 records to demonstrate that the testing and verification of the internal communication plan had occurred. CSC confirmed that records for 2021 and 2022 did not exist.

Thus, CSC's testing and verification of the internal communication plan for manual operations was not completed in calendar years 2021 and 2022 as required by § 195.446(c)(3).

6. § 195.446 Control room management.

(a) General. This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .
(b) . . . .
(c) Provide adequate information. Each operator must provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities the operator has defined by performing each of the following:
(1) . . . .
(4) Test any backup SCADA systems at least once each calendar year, but at intervals not to exceed 15 months; and. . . .

CSC failed to test any backup SCADA systems at least once per calendar year, but at intervals not to exceed 15 months, in accordance with §§ 195.446(c)(4) and 195.446(j)(2). CSC's records did not demonstrate that the backup SCADA system was adequately tested per the regulatory timeframe of once per calendar year, but at not to exceed 15 months. While the testing of the backup server for calendar years 2020 and 2021 had a checked box that the server was switched from server 1 to server 2, CSC did not maintain any records demonstrating what was tested associated with the server switch or that various commands were tested on the backup server. CSC's procedures in 4.7.1.1, "System Failover to NCC Disaster Recovery Center," stated that specific tests will confirm that the backup control center SCADA server properly assumes the main control responsibilities with minimal interruptions to operations.

Further, this procedure indicated in item 6 that the operator is to verify that the system is communicating normally, and any/all AOCs documented in the previous sections are unchanged.

In item 7, the procedure indicated that operations should verify that data is changing throughout the system and if possible, send commands or setpoints to a remote facility. However, nothing was available in the records to demonstrate that operations had been verified to be communicating normally, that operations had verified that data is changing throughout the system, or that commands or setpoints were changed. Thus, there is nothing demonstrating the procedure was followed.

By failing to demonstrate that the test of the SCADA system was adequately performed, and that control was successfully established on the backup server, CSC failed to demonstrate that it adequately tested its backup servers, in compliance with §§ 195.446(c)(4) and 195.446(j)(2).

7. § 195.446 Control room management.

> **(a) General. This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .**
> **(b) . . . .**
> **(d) Fatigue mitigation. Each operator must implement the following methods to reduce the risk associated with controller fatigue that could inhibit a controller's ability to carry out the roles and responsibilities the operator has defined:**
> **(1) Establish shift lengths and schedule rotations that provide controllers off-duty time sufficient to achieve eight hours of continuous sleep;**

CSC failed to establish shift lengths and schedule rotations that provided controllers off-duty time sufficient to achieve eight hours of continuous sleep, per the requirements of § 195.446(d)(1). PHMSA reviewed CSC's schedule rotation for January 2022. CSC's schedule did not define the maximum hours to be worked for each shift nor did it identify who was working what specific console. Console 7 and Console 8 controllers were cross-trained. Console 8 had the CSC assets. CSC's schedule rotations did not identify which employee was working Console 8 per shift. Absent this identification, CSC could not ensure that scheduled rotations and established shift lengths provided controllers off-duty time sufficient to achieve eight hours of continuous sleep.

Additionally, PHMSA reviewed the records for August 2021 and determined that the existing records were insufficient to demonstrate who worked on which console and/or to determine who was scheduled to work on each specific console. While CSC used a different color to delineate days and nights, CSC did not document anything else beyond the date assignment, nothing clearly delineated who worked which console. When PHMSA reviewed the records for September and December 2020, PHMSA could not tell whether the controllers were assigned to work on days or nights, or what console each employee was assigned to. Therefore, CSC failed to establish shift lengths and schedule rotations that provided controllers off-duty time sufficient to achieve eight hours of sleep between September 2020 and January of 2022, per the requirements of § 195.446(d)(1).

8. § 195.446 Control room management.

> **(a) General. This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .**
> **(b) . . . .**
> **(e) Alarm management. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:**
> **(1) . . . .**
> **(2) Identify at least once each calendar month points affecting safety that have been taken off scan in the SCADA host, have had alarms inhibited, generated false alarms, or that have had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities;**

CSC failed to identify, at least once each calendar month, points affecting safety that have been taken off scan in the SCADA host, had alarms inhibited, generated false alarms or that had forced or manual values for periods of time exceeding that required for associated maintenance or operating activities, per the requirements of § 195.446(e)(2). During the inspection PHMSA determined the following:

1. CSC failed to conduct a monthly review of points affecting safety in:
    a. February of 2022; and
    b. March of 2021.

2. CSC mis-dated multiple monthly reviews of points affecting safety:
    a. The August, September, October, November, and December 2021 reports were all incorrectly dated February 1, 2022;
    b. The September 2020 report was incorrectly dated November 30, 2020;
    c. The July 2020 report was incorrectly dated September 2, 2020; and
    d. The May 2020 report was incorrectly dated July 31, 2020.

In addition, none of the CSC monthly reviews of points affecting safety included a review of alarms inhibited, false alarms, forced values that occurred in the Programmable Logic Controllers (PLCs) or manual positions for field equipment exceeding periods of time required for maintenance or operating activities.

Therefore, CSC failed to demonstrate compliance with § 195.446(e)(2), as its reviews were (1) incomplete or not finished and (2) records were dated in a way that had several months of reviews done at the same time or the records provided failed to identify whether all alarms had been adequately checked for all conditions identified in § 195.446(e)(2) on a monthly basis.

9. § 195.446 Control room management.

> **(a) General. This section applies to each operator of a pipeline facility with a controller working in a control room who monitors and controls all or part of a pipeline facility through a SCADA system. Each operator must have and follow written control room management procedures that implement the requirements of this section. . . .**
> **(b) . . . .**
> **(e) Alarm management. Each operator using a SCADA system must have a written alarm management plan to provide for effective controller response to alarms. An operator's plan must include provisions to:**
> **(1) . . . .**
> **(6) Address deficiencies identified through the implementation of paragraphs (e)(1) through (e)(5) of this section.**

CSC failed to address deficiencies identified through the implementation of §§ 195.446(e)(1) through (e)(5), per § 195.446(e)(6). Specifically, CSC was unable to present any records demonstrating that it addressed any of the alarm management deficiencies listed in §§ 195.446(e)(1) through (e)(5). For example, PHMSA reviewed the bad actor reports[5] that were part of the monthly alarm reviews. In September of 2021, multiple hihi[6] alarms were received associated with breakout tanks 111 and 112. In October of 2021, breakout tank 111 hihi alarm again occurs multiple times. However, nothing identified how these alarms, which fall under § 195.446(e), had been addressed between monthly reviews.

Therefore, CSC failed to meet the requirements of § 195.446(e)(6) as none of the deficiencies presented at the time of the inspection, including those reviewed as part of monthly alarm bad actor reports were addressed.

10. § 195.452 Pipeline integrity management in high consequence areas.

> **(a) Which pipelines are covered by this section? This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area . . . .**
> **(b) . . . .**
> **(i) What preventive and mitigative measures must an operator take to protect the high consequence area?**
> **(1) . . . .**

[5] Bad Actor Reports are reports that list points that have the same alarms repeatedly occurring within a given time frame. These are a type of false alarms.
[6] Hihi is an alarm setpoint parameter or attribute. This is an alarm setpoint value for a point or logic condition that can have an assigned priority requiring a specific controller response time.

(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.**

Caliber failed to evaluate the capability of its leak detection means as required by § 195.452(i)(3). Specifically, Caliber failed to evaluate the capability of its leak detection means and modify, as necessary, to protect the high consequence area. Caliber had:

1. 4.46 miles of could affect HCA, as identified in the 2023 annual report addressing 2022 mileage;
2. 10.86 miles of could affect HCA, as identified in the 2022 annual report addressing 2021 mileage; and
3. 10.38 miles of could affect HCA, as identified in the 2021 annual report addressing 2020 mileage.

CSC was unable to provide any documentation that demonstrated an evaluation had been completed regarding the capability of the leak detection means including the specific factors of 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 the nearest response personnel, leak history, and risk assessment results in calendar years 2020-2022, as required by § 195.452(i)(3).

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 $95,600 as follows:

Item number	PENALTY
1	$ 22,400
4	$ 50,100
8	$ 23,100

Proposed Compliance Order

With respect to Item 2 and Item 10 pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Midstream Partners, LP, Caliber Spring Creek, 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, 5, 6, 7, and 9, 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. We advise you to promptly correct these items. Failure to do so may result in additional enforcement action.

Response to this Notice

This Notice is issued in accordance with 49 CFR § 190.207(c). Any response you may have submitted to the original Notice is no longer applicable. You must respond as set forth below.

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 3-2025-001-NOPV** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

David Barrett
Acting Director, Central Region, Office of Pipeline Safety
Pipeline and Hazardous Materials Safety Administration

cc: Charles Maybee, Director of Operations, Caliber Midstream Partners, LP, cmaybee@callibermidstream.com
Nephi Eddy, Operations Manager, Caliber Midstream Partners, LP, neddy@callibermidstream.com

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

PROPOSED COMPLIANCE ORDER

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

A. In regard to Item 2 of the Notice, pertaining to the failure to evaluate the capability of its leak detection system for the portion of the Spring Creek pipeline system (known as the Southeast Extension) constructed after October 1, 2019, Caliber is required to conduct this evaluation and submit the outcome of this evaluation, along with any associated documentation and related records, to the Central Region Director within **90** days of receipt of the Final Order.

B. In regard to Item 10 of the Notice, pertaining to the portion of the Spring Creek pipeline system constructed prior to October 1, 2019 and the failure to evaluate the capability of its leak detection system to protect the high consequence area, Caliber is required to conduct this evaluation and submit the outcome of this evaluation, along with any associated documentation and related records, to the Central Region Director within **90** days of receipt of the Final Order.

C. It is requested that Caliber maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to David Barrett, Acting Director, Central Region, 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.