U.S. Department
of Transportation
**Pipeline and Hazardous
Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

NOTICE OF PROBABLE VIOLATION
and
PROPOSED COMPLIANCE ORDER

VIA ELECTRONIC MAIL TO: John.sims@enstarnaturalgas.com

May 23, 2024

Mr. John Sims
President
Alaska Pipeline Company
PO Box 190288
Anchorage, AK 99519

CPF 5-2024-016-NOPV

Dear Mr. Sims:

From January 18, 2023, to May 10, 2023, a representative 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 Alaska Pipeline Company's (APC) Beluga Gas Natural Gas Transmission Line System in the Matanuska-Susitna and Anchorage Boroughs of Alaska.

As a result of the inspection, it is alleged that you 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. § 192.201 Required capacity of pressure relieving and limiting stations.

(a) Each pressure relief station or pressure limiting station or group of those stations installed to protect a pipeline must have enough capacity, and must be set to operate, to insure the following:
(1)…
(2) In pipelines other than a low pressure distribution system:
(i) If the maximum allowable operating pressure is 60 p.s.i. (414 kPa) gage or more, the pressure may not exceed the maximum allowable operating pressure plus 10 percent, or the pressure that produces a hoop stress of 75 percent of SMYS, whichever is lower;

APC failed to set its pressure relief valves (PRV) to setpoints that account for a capacity of the maximum allowable operating pressure (MAOP) plus 10 percent, as required per § 192.201(a)(2)(i). Specifically, during inspection, PHMSA observed that the pipeline was operated with three PRVs with setpoints that were between 4% and 6% higher than the MAOP of 1031 pounds per square inch gauge (psig). The Ivan River lateral PRV was set at 1100 psig, the Lewis River lateral PRV was set at 1077 psig, and the Pretty Creek lateral was set at 1105 psig. In the event of a pipeline overpressure, assuming a 10% PRV accumulation, the pressure in the system would exceed the MAOP plus 10% regulatory limit.

PRV setpoints must be equal or less than the MAOP to meet the requirements of § 192.201(a)(2)(i). Otherwise, APC must show documentation that the PRV has a reduced accumulation (i.e. pressure difference between the PRV cracking open at the setpoint and being full open) that will result in the PRV being full open at the MAOP plus 10% regulatory limit. However, a review of APC's records indicated that the Ivan River lateral PRV, Lewis River lateral, and the Pretty Creek lateral do not have reduced regulation that would exempt them from having setpoints equal or less than the MAOP as required by § 192.201(a)(2)(i).

Therefore, APC failed to set its pressure relief valves (PRV) to setpoints that account for a capacity of the maximum allowable operating pressure (MAOP) plus 10 percent, as required per § 192.201(a)(2)(i).

2. § 192.605 Procedural manual for operations, maintenance, and emergencies.

(a) …
(b) *Maintenance and normal operations.* The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.
(1) Operating, maintaining, and repairing the pipeline in accordance with each of the requirements of this subpart and Subpart M of this part.

APC failed to have procedures for operating, maintaining and repairing the pipeline in accordance with each requirement of Subpart M, as required.

Specifically, § 192.739 requires annual inspection and calibration of each pressure limiting station, relief device. Additionally §192.743 requires that each pressure limiting station, relief device be annually reviewed for sufficient capacity.

However, APC's procedures did not specify collection and review of documents and calculations for the pressure safety devices located upstream of its facilities. Those pressure safety devices provide protection to the Beluga Transmission Line. During inspection, a review of APC's Standard Operating Procedures Manual #1330, Over-Pressure Protection Testing and Review section, revealed that while APC had procedures for testing overpressure devices maintained by itself, APC did not have procedures for pressure testing and record retention of relief devices on upstream facilities that protect its transmission lines but are operated by other companies. The manual also failed to mandate APC retain documentation of the annual PRV capacity calculation reviews for both APC owned and other company owned/operated PRVs that protect its transmission lines. Additionally, the manual did not have procedures requiring APC to obtain and retain Operator Qualification documentation for inspections and calibrations of overpressure devices that protect its transmission lines but are operated by other companies.

Further, a review of APC's records demonstrated that it had not completed annual capacity reviews for two of its PRVs since 2011.

Therefore APC failed to have procedures for operating, maintaining, and repairing its pipeline in accordance with each requirement in Subpart M as required pursuant to § 192.605(a).

3. § 192.615 Emergency plans.

(a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following:
(1)…
(2) Establishing and maintaining adequate means of communication with the appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials. Operators may establish liaison with the appropriate local emergency coordinating agencies, such as 9- 1-1 emergency call centers or county emergency managers, in lieu of communicating individually with each fire, police, or other public entity. An operator must determine the responsibilities, resources, jurisdictional area(s), and emergency contact telephone number(s) for both local and out-of-area calls of each Federal, State, and local government organization that may respond to a pipeline emergency, and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies.

APC failed to establish procedures to maintain adequate means of communication with the appropriate public safety answering point (i.e., 9-1-1 emergency call center), where direct access to a 9-1-1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials as required by § 192.615.

Upon inspector request, APC was unable to provide such procedures to demonstrate they existed anywhere in the manual. During the inspection, a representative of the operator's specifically stated that they did not currently coordinate with 9-1-1 Dispatch Centers to verify that Dispatch Centers have procedures to respond to public reports of pipeline rupture, pipeline fire, and "I smell gas" phone calls; further demonstrating that such procedures did not exist.

Therefore, APC failed to create written procedures requiring coordination with the appropriate public safety answering point as required per § 192.615.

4. § 192.739 Pressure limiting and regulating stations: Inspection and testing.

(a) Each pressure limiting station, relief device (except rupture discs), and pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is-
(1) In good mechanical condition;
(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;
(3) Except as provided in paragraph (b) of this section, set to control or relieve at the correct pressure consistent with the pressure limits of §192.201(a); and
(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.

The Operator failed to conduct the annual inspections and calibrations required by 192.739(a) on multiple pressure limiting station relief devices. This was evidenced by lack of inspection and calibration records as required by §192.709.

Specifically, the Operator was unable to provide pressure relief valve documentation proving annual inspection and calibration of the Harvest pressure relief valve MP0 TY-BJ-PSV001 as required by § 192.739(a).

Additionally, the Operator failed to provide calibration information for APC PRVs B601 and B604. While the Operator did provide some PRV inspection information for the B601 and B604 PRVs on the Regulator Station Maintenance Record form, such as isolation valves, regulators and PRVs, the Operator did not fully document the calibration of the PRVs at each station; the abbreviation legend provided an Adjusted-A option that was not utilized. In comparison, calibrations of the W-PSV-0370 Lewis River and W-PSV-0562 Pretty Creek PRVs were fully documented on the Partial Filled Test/Repair Data Form.[a]

Therefore, the Operator failed to conduct the annual inspections and calibrations on pressure relief valves TY-BJ-PSV001, B601 and B604 as required by 192.739(a).

5. § 192.743 Pressure limiting and regulating stations: Capacity of relief devices.

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

The Operator failed to determine the relief capacity of three pressure relief valves as required by §192.743(b). The Operator failed to conduct annual relief valve calculation reviews on two pressure relief valves as required by §192.743(a). These failures were evidenced by a lack of records demonstrating completion as required by §192.709.

Specifically, the Operator was unable to provide PRV capacity calculations for pressure relief valves APC PSV B601-15R, APC PSV B604.14R Ivan River and Harvest MP0 TY-BJ-PSV001 as required by § 192.739(b). The Operator was also unable to provide documentation demonstrating annual review of these calculations as required by § 192.739(a). Because the Operator is unable to provide records to the contrary, PHMSA contends that the required relief valve capacity calculations were not completed.

Additionally, the Operator provided PRV capacity calculations for W-PSV-0370 Lewis River and W-PSV-0562 Pretty Creek that were dated 2011. Upon request, the Operator was unable to provide documentation demonstrating annual review of these documents between 2012 and 2023, as required by §192.739(a). Because the Operator is unable to provide records to the contrary, it is PHMSA's contention that the annual reviews required by §192.739(a) were not completed.

Therefore, the Operator failed to determine and document the relief capacity of three pressure relief valves as required by §192.743(b) and failed to complete over 10 years of relief valve capacity calculation annual reviews, for two relief valves, as required by §192.743(a).

[a] For reference, the Beluga pipeline is supplied from five production lines, each with a PRV. Two PRVs are owned by APC (B601-15R, B604-14R Ivan River), two by Hilcorp (W-PSV-0370 Lewis River, W-PSV-0562 Pretty Creek) and one by Harvest (MP0 TY-BJ-PSV001).

6. **§ 192.743 Pressure limiting and regulating stations: Capacity of relief devices.**

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

The Operator failed to determine the relief capacity of multiple relief devices valves as required by §192.743(b). These failures were evidenced by a lack of records as required by §192.709.

Specifically, the Operator was unable to provide relief capacity calculations for the vent and relief devices on the top of the horizontal condensate holding tank, located at the MP39 site.

The Beluga Gas Transmission line was operated at approximately 700 psig and was connected to a vertical, high pressure condensate knockout drum on the MP39 site. Two regulators in parallel controlled the gas and condensate flow between the vertical knockout drum and the horizontal condensate tank. The nameplate rating on the horizontal tank is 5 psig. PHMSA contends that a leak, fire or rupture related to this tank would affect transmission line operation and therefore it is part of the transmission line system and facilities.

The Operator stated during the field inspection that they did not consider this horizontal condensate holding tank to be part of the regulated transmission line system and that capacity calculations for the tank vent and relief devices had not been created.

Therefore, the Operator failed to determine the relief capacity of multiple relief devices valves as required by §192.743(b).

7. **§192.807 Recordkeeping.**

Each operator shall maintain records that demonstrate compliance with this subpart.
(a) Qualification records shall include:
(1) Identification of qualified individual(s);
(2) Identification of the covered tasks the individual is qualified to perform;
(3) Date(s) of current qualification; and
(4) Qualification method(s).
(b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

The Operator failed to obtain and maintain qualification records as required by §192.807 for individuals that completed, or should have completed, inspection and calibration tasks required by §192.739, for three upstream, producer owned, pressure relief valves that provide protection to the APC Beluga pipeline.

Specifically, upon request, the Operator was unable to provide operator qualification (OQ) documentation for personnel inspecting and calibrating the following pressure relief valves on upstream facilities operated by another company: W-PSV-0370 Lewis River, W-PSV-0562 Pretty Creek and MP0 TY-BJ-PSV001. In a letter from the Operator to the inspector dated 11/28/2023 the Operator stated "It is not a requirement for APC to maintain operator qualification records for another operator where APC is not performing the covered task." However, the recordkeeping requirements outlined in §192.807 are applicable to records which document compliance with the Pipeline Safety Regulations. The Operator is required to maintain records which demonstrate covered tasks for their facilities were completed by qualified personnel. Inspection and calibration of overpressure protection devices is a covered task.

Part §192.195 requires that a gas transmission operator ensure overpressure protection of their transmission line. Even if the overpressure protection devices are operated by another company, the Operator is still responsible for verifying annual maintenance and annual calibration, that annual relief capacity review requirements are completed by qualified individuals and obtaining and retaining the appropriate documentation.

Therefore, the Operator failed to obtain and maintain qualification records as required by §192.807 covering employees that inspected and calibrated multiple relief devices.

8. §192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

(a) *Definition.* ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline.
(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, see § 192.7), section 6.4, and in NACE SP0502 (incorporated by reference, see § 192.7).

The Operator failed to fully complete external corrosion direct assessments (ECDA), as required by §192.925, on multiple APC Beluga laterals that were subject to the integrity re-assessment requirements by §192.937(a).

Specifically, the Operator failed to conduct one direct examination in the "CDA region identified as most likely for external corrosion in the Pre-assessment Step" for each of the following laterals: B17-B26-B52 Palmer Lateral, B25 Vine Lateral, B22-B56 Seward Meridian Lateral and

B10-B11 Wasilla Lateral. The direct assessment step includes digging a bellhole and directly inspecting a small portion of the pipeline using ultrasonic and/or other non-destructive techniques.

Additionally, for each lateral, the Operator failed to identify the ECDA region identified as most likely for external corrosion in the Pre-assessment step and complete the direct assessment step according to NACE Standard 0502-2010, Paragraph 5.3.1.1. "In the event that no indications are identified in a pipeline segment, a minimum of one direct examination is required in the ECDA region identified as most likely for external corrosion in the Pre-assessment Step."

To meet the integrity re-assessment requirements by §192.937(a), the Operator chose ECDA from the eight allowable methodologies listed in §192.937(c).

The requirements for an ECDA inspection are outlined in §192.925. ECDA is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline. Instead of the ECDA, the Operator documented completion of the indirect inspection for each lateral using the close interval survey (CIS) and direct current voltage gradient (DCVG) techniques and stated that no indications were found.

The Operator stated during the Records review that they did not complete an excavation dig for each pipeline segment because the Operator considered all of the laterals to be single pipeline segments despite their varying locations and the distances between them. The Operator completed one direct examination at Eklutna Lateral, and considered this sufficient to meet the requirements of the ECDA inspection. ECDA inspection reports submitted had a statement confirming a direct assessment was not done on Palmer Laterals, Seward Meridian Lateral, and Wasilla Laterals: "The corrosion department did not recommend any excavations within this HCA."

The requirement is that at least one direct examination (confirmatory dig) must be done for every pipeline segment, within an HCA segment. In determining pipeline segments, consideration should be given to location-specific factors such as soil acidity, soil type, soil moisture, soil water content, native voltage level, stray currents, and other differences such as cathodic protection. Due to consideration of these factors PHMSA contends that the Vine, Wasilla, Seward Meridian, Palmer and Eklutna are independent segments, each requiring a confirmatory dig as part of a pipeline integrity reconfirmation if they are within an HCA.[b]

Therefore, the Operator failed to complete external corrosion direct assessments (ECDA) on four APC Beluga pipeline laterals, which were required by the integrity re-assessment requirements of §192.937(a).

[b] *See*, ASME B31.8S and NACE Std 0502 definitions of pipeline segment and ECDA region.

Proposed Civil Penalty

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to 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. For violation occurring on or after November 27, 2018 and before July 31, 2019, the maximum penalty may not exceed $213,268 per violation per day, with a maximum penalty not to exceed $2,132,679.

We have reviewed the circumstances and supporting documents involved in this case, and have decided not to propose a civil penalty assessment at this time.

Proposed Compliance Order

With respect to items 1, 4, 5, 6, 7 and 8 pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to Alaska Pipeline Company. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Warning Items

With respect to items 2 and 3 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

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 5-2024-016-NOPV** and, for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

DUSTIN B HUBBARD Digitally signed by DUSTIN B HUBBARD
Date: 2024.05.23 10:55:38 -06'00'

Dustin Hubbard
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

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

cc: PHP-60 Compliance Registry
PHP-500 C. Lyon (#23-264378)
Rusty Allen, Alaska Pipeline Company, rusty.allen@enstarnaturalgas.com

PROPOSED COMPLIANCE ORDER

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

A. In regard to 1 of the Notice pertaining to the Ivan River, Lewis River and Pretty Creek pressure relief valves (PRVs) that have setpoints above the maximum allowable operating pressure (MAOP) of the pipeline, Alaska Pipeline Company must, for each PRV, provide documentation within **90** days of receipt of the Final Order to the Western Region Director demonstrating PRV setpoints are no longer greater than the system MAOP, or that each PRV setpoint's accumulation pressure has been reviewed to ensure in a relief event the net setpoint ensures system pressure will not exceed the MAOP plus 10% MAOP regulatory requirement.

B. In regard to 4 of the Notice pertaining to required inspection and calibration records of MP0 TY-BJ-PSV001 PSV, B601 and B604. Alaska Pipeline Company must provide the documentation to the Western Region Director within **180** days of receipt of the Final Order demonstrating the activities were completed.

C. In regard to 5 of the Notice pertaining to missing relief capacity records, the Alaska Pipeline Company must provide the following documents to the Western Region Director within **180** days of receipt of the Final Order.
[a] Create and submit PRV capacity calculations for PRVs: B601-15R, B604.14R Ivan River and MP0 TY-BJ-PSV001.
[b] Conduct, document and submit an engineering review of the PRV capacity calculations for PRVs: W-PSV-0370 Lewis River and W-PSV-0562 Pretty Creek.

D. In regard to 6 pertaining to relief capacity calculations for the vent and relief devices on the top of the horizontal condensate holding tank located at the MP39 site the Alaska Pipeline Company must provide the following documents to the Western Region Director within **180** days of receipt of the Final Order.
[a] Create and submit PRV capacity calculations for the vent and relief devices on top of the horizontal condensate tank.
[b] Inspect and calibrate the relief capacity devices.

E. In regard to 7 of the Notice pertaining to qualifications of personnel completing PRV inspections, Alaska Pipeline Company must provide documentation to the Western Region Director within **90** days of receipt of the Final Order demonstrating inspections of PRVs WS-RV-582 Lewis River PSV, WS-RV-550

Pretty Creek PRV and MP0 TY-BJ-PRV001 PRV have been completed by qualified personnel.

F. In regard to 8 of the Notice pertaining to Operator failure to conduct EDCA confirmatory digs to the requirements of NACE Standard 0502-2010 for their seven year integrity review, Alaska Pipeline Company must submit documentation to the Western Region Director within **180** days of receipt of the Final Order demonstrating:
[a] Review the seven year integrity evaluation for every APC Beluga pipeline lateral that contains an HCA and that is not ILI capable, for which the ECDA methodology is used. For each lateral, verify that the "CDA region identified as most likely for external corrosion in the Pre-assessment Step" was selected and appropriately documented.
[b] If a direct examination (confirmatory dig) was not completed in the "CDA region most likely for external corrosion" for each pipeline lateral; schedule and conduct these examination(s).
[c] Submit a revised ECDA confirmatory dig report, including photos, for each lateral in the APC Beluga Transmission Pipeline System.

G. It is requested (not mandated) that Alaska Pipeline Company maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Dustin Hubbard, Director, Western 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.