



U.S. Department
of Transportation

Pipeline and Hazardous Materials
Safety Administration

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

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

January 25, 2019

Mr. Greg Lalicker
Chief Executive Officer
Hilcorp Alaska, LLC
1111 Travis Street
Houston, Texas 77002

CPF 5-2019-2002W

Dear Mr. Lalicker:

On July 11 through 15, 2016 and October 26, 2016, 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 Hilcorp Alaska, LLC's (Hilcorp) Middle Ground Shoal natural gas transmission pipeline system near Nikiski, Alaska. We also reviewed your operation, maintenance and emergency response procedures and supporting records at your Nikiski and Anchorage offices.

Based on our inspection findings, PHMSA determined that Hilcorp committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations (CFR). The deficiencies noted and the probable violations are:

- 1. §191.5(a) Immediate notice of certain incidents.**
(a) At the earliest practicable moment following discovery, each operator shall give notice in accordance with paragraph (b) of this section of each incident as defined in §191.3.

Records do not indicate immediate notifications of incidents were made in accordance with §191.5. The previous operator failed to provide notice to the National Response Center of a natural gas leak on August 31, 2014, as confirmed by the Hilcorp personnel interviewed.

- 2. **§ 191.15 Transmission systems; gathering systems; and liquefied natural gas facilities: Incident report.**
 - (a) **Transmission or Gathering.** Each operator of a transmission or a gathering pipeline system must submit DOT Form PHMSA F 7100.2 as soon as practicable but not more than 30 days after detection of an incident required to be reported under §191.5 of this part.

Records do not indicate that transmission incident reports were submitted by the previous operator to DOT on Form 7100.2 (01-2002) within the required timeframe. Incident reports were not submitted for the June 1, 2014 and August 31, 2014 leaks on the transmission pipeline system.

- 3. **§ 191.22 National Registry of Pipeline and LNG Operators (OPID)**
 - (c) **Changes.** Each operator of a gas pipeline, gas pipeline facility, LNG plant or LNG facility must notify PHMSA electronically through the National Registry of Pipeline and LNG Operators at <http://opsweb.phmsa.dot.gov> of certain events.

Hilcorp failed to submit a National Registry notification to PHMSA regarding the September 1, 2015 purchase of the Middle Ground Shoal natural gas transmission pipeline system.

- 4. **§ 192.481 Atmospheric corrosion control: Monitoring**
 - (a) **Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:**

If the pipeline is located:	Then the frequency of inspection is:
Onshore	At least once every 3 calendar years, but with intervals not exceeding 39 months
Offshore	At least once each calendar year, but with intervals not exceeding 15 months

Hilcorp could not demonstrate that all portions of the pipeline that were exposed to the atmosphere were inspected at the required time interval. Records provided to our inspectors do not adequately document inspection of aboveground pipe for evidence of atmospheric corrosion. Offshore atmospheric corrosion inspections for pipeline portions located on the Platform A were not conducted in 2015.

5. **§ 192.605 Procedural manual for operations, maintenance, and emergencies.**
(a) **General.** Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least once each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

The operators failed to conduct a review of its emergency plans and procedures at intervals not exceeding 15 months, but at least once each calendar year. The Emergency Plans and Procedures were reviewed on December 3, 2013 and again on November 24, 2015. The interval between reviews was longer than 15 months, and no review was completed during the 2014 calendar year.

The previous operator also failed to document that annual reviews of the written procedures in the operations and maintenance manual were conducted as required. Hilcorp was unable to demonstrate that an annual review of operations and maintenance plans and procedures had been conducted in the 2014 calendar year.

6. **§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.**
(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:
(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part. However, for steel pipe in pipelines being converted under §192.14 or uprated under subpart K of this part, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, one of the following pressures is to be used as design pressure:
(i) Eighty percent of the first test pressure that produces yield under section N5 of Appendix N of ASME B31.8 (incorporated by reference, *see* §192.7), reduced by the appropriate factor in paragraph (a)(2)(ii) of this section; or
(ii) If the pipe is 12³/₄ inches (324 mm) or less in outside diameter and is not tested to yield under this paragraph, 200 p.s.i. (1379 kPa).

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

- (i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.
- (ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Class location	Factors ¹ , segment—		
	Installed before (Nov. 12, 1970)	Installed after (Nov. 11, 1970)	Converted under §192.14
1	1.1	1.1	1.25
2	1.25	1.25	1.25
3	1.4	1.5	1.5
4	1.4	1.5	1.5

¹ For offshore segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
—Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
—Onshore transmission line that was a gathering line not subject to this part before March 15, 2006		
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

- (4) **The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.**
- (b) **No person may operate a segment to which paragraph (a)(4) of this section is applicable, unless over-pressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.**
- (c) **The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.**
- (d) **The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in §192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under §192.620(a).**

Hilcorp did not properly determine the maximum allowable operating pressure (MAOP) per §192.619 and §192.620 for the transmission pipelines between Platform A to Platform C, and Platform C to the Dillon Platform. The maximum allowable operating pressure for these pipelines must be determined by §192.619(a), §192.619(c), or §192.619(d) requirements. Hilcorp's MAOP determination does not attempt to address §192.619(c) requirements. Hilcorp has not identified these pipelines as alternative MAOP pipelines and, therefore, the 192.619(d) requirements are not applicable. Because Hilcorp did not perform the necessary analysis required to proceed under §192.619(c) or § 192.619(d), §192.619(a) requirements govern. In order to meet §192.619(a) requirements, Hilcorp must select the lowest of four values determined by §§192.619(a)(1) – (a)(4). Hilcorp states that due to the lack of information, including pressure test documentation, the MAOP of these lines was determined by the requirements of §192.619(a)(4). This is inadequate, for without determining the appropriate values for §§192.619(a)(1) - (a)(3), it cannot be determined if the §192.619(a)(4) value is the lowest of the four values.

- 7. **§ 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;**

Our field inspection revealed that pressure regulating control lines were not supported in a manner to prevent damage so that they maintain good mechanical condition. Control lines

associated with the pressure reduction equipment (PV-1210 and PV-1211) within the Distribution Building were not adequately supported and therefore unsafe.

Records do not indicate inspection and testing of a pressure relief device as required and at the specified intervals. The operators failed to inspect and test PSV-2007 at intervals not exceeding 15 months, but at least once each calendar year to determine its mechanical condition, capacity, and reliability of operation for the service in which it is employed.

PSV-2007 was tested on September 4, 2014, placed into service on August 24, 2015, and remained in service until July 6, 2016. PSV-2007 was in-service in calendar year of 2015 without being inspected or tested. In addition, PSV-2007 remained in service until July 6, 2016, which exceeded the 15 month interval.. Therefore, the PSV-2007 was in-service while exceeding the inspection and testing interval required by code.

8. § 192.745 Valve maintenance: Transmission lines.

(a) Each transmission line valve that might be required during any emergency must be inspected and partially operated at intervals not exceeding 15 months, but at least once each calendar year.

During the inspection, Hilcorp identified two safety valves on Platform A (SDV-1810A and SDV-2700), and three safety valves on Platform C (FDD-1610, SDV-1600, and SDV-1610) that would be required during an emergency. The prior operator of these platforms, XTO, previously identified only one safety valve each on Platform A and Platform C.

Hilcorp was unable to provide a record of inspection and partial operation of the transmission line valves which were located on Platform A and Platform C during the calendar years: 2013, 2014, and 2015.

9. § 192.743(a) 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.

Records indicate testing or review of the capacity of each pressure relief device at each pressure limiting station and pressure regulating station was not completed as required. Hilcorp provided pressure relief capacity calculations/reviews dated September 10, 2010 and December 14, 2015. The September 2010 calculations/reviews were done when XTO was the operator, and the December 2015 calculations/reviews were done by Hilcorp. No other calculations/reviews were provided. Pressure relief capacity reviews were not conducted in the following calendar years: 2011, 2012, 2013, and 2014.

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to exceed \$209,002 per violation per day the violation persists, up to a maximum of \$2,090,022 for a related series of violations. For violations occurring prior to November 2, 2015, the maximum penalty may not exceed \$200,000 per violation per day, with a maximum penalty not to exceed \$2,000,000 for a related series of violations. 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 correct the item(s) identified in this letter. Failure to do so will result in Hilcorp being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 5-2019-2002W**. Be advised that all material you submit in response to this enforcement action is subject to being 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).

Sincerely,



Chris Hoidal
Acting Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: David S. Wilkins, Senior Vice President, Alaska
Erin McKay, Regulatory Compliance Manager Alaska Integrity Group
PHP-60 Compliance Registry
PHP-500 M. Chard, T. Johnson (#152927)