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

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

NOTICE OF PROBABLE VIOLATION
PROPOSED CIVIL PENALTY
and
PROPOSED COMPLIANCE ORDER

VIA E-MAIL TO MR. DAX SANDERS

May 12, 2021

Mr. Dax Sanders
President of Products Pipelines
Kinder Morgan, Inc.
1001 Louisiana Street, Suite 1000
Houston, Texas 77002

CPF 5-2021-022-NOPV

Dear Mr. Sanders:

On December 15 through 21, 2018, May 1 through 3, 2019, and June 3 through 5, 2019, pursuant to 49 U.S.C. § 60117, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), responded to an incident that occurred on Santa Fe Pacific Pipeline Partners, LP's (SFPP) 12-inch diameter El Paso-to-Tucson (SFPP 12-inch EPT) Pipeline near Anthony, New Mexico. SFPP is a subsidiary of Kinder Morgan, Inc. (KMI).[1]

At approximately 23:40 MST on December 13, 2018, the SFPP 12-inch EPT Pipeline ruptured,

[1] Kinder Morgan, Inc., transports crude oil, refined petroleum products, and highly volatile liquids through approximately 9,500 miles of product pipelines in the United States. Kinder Morgan website, *available at* https://www.kindermorgan.com/pages/business/products_pipelines/ (last accessed May 26, 2020).

resulting in a release of approximately 11,000 barrels of gasoline into a drainage ditch (Failure).[2] The Failure site was on the partially-buried down-stream segment of the El Paso-to-Tucson pipe at or near the western edge bank of the Anthony Drain canal and was in contact with soil.[3] The 12-inch EPT Pipeline traverses or is in close proximity to numerous high consequence areas (HCAs), including unusually sensitive areas (USAs), as defined in 49 C.F.R. Part 195. The Failure site occurred on a segment that "could affect" a USA. This ruptured segment is located in the Elephant Butte's Irrigation District (EBID) in the Mesilla Valley, a highly productive agricultural area that borders the Rio Grande River.

The mainline valves on both sides of the Failure site are manually-operated valves and are near the same elevation as the drainage ditch. The topography of the area indicates that the pipeline descends approximately 900 vertical feet from the east downwards and towards the Failure site. Small elevation changes occur between the mainline valve to the west and the Failure site. It appears much of the released volume of gasoline was a result of the pipeline draining down from the high areas to the east.

Following the Failure, PHMSA deployed two investigators to the Failure site to conduct an investigation into the Failure and its cause(s). On December 28, 2018, PHMSA issued a Notice of Proposed Safety Order, CPF No. 5-2018-5007S, to KMI, alleging that the continued operation of SFPP's 12-inch EPT Pipeline posed an integrity risk to public safety, property, or the environment related to the Failure (NOPSO).[4] PHMSA proposed that KMI take certain corrective actions to address this risk, including exposed-pipe surveys, inline inspections, data integration, remediation and repair of anomalies or defects consistent with atmospheric corrosion and integrity management regulations, emergency flow restricting devices (EFRD) studies, a root cause failure analysis, and various revisions of its operating procedures. On January 22, 2019, KMI responded to the NOPSO but did not contest the proposed findings or remedial actions. On August 8, 2019, PHMSA issued a final Safety Order, finding that continued operation of the SFPP 12-inch EPT Pipeline without corrective or remedial measures would pose a pipeline integrity risk.[5] The Safety Order adopted the preliminary findings and remedial measures set forth in the NOPSO.[6] To date, KMI has completed many of the required remedial measures.

---

[2] KMI initially reported the volume of the release to be approximately 6,000 barrels, but later updated the spill amount to 11,000 barrels.

[3] KMI Updated RCFA, Incident Investigation Summary (Jan. 17, 2020), at 2 (on file with PHMSA). Coating at the Failure site was tape wrap. *Id.*

[4] For purposes of the NOPSO and Safety Order, the SFPP 12-inch EPT line was the entire 288-mile long 12-inch EPT Pipeline that delivers refined petroleum products westward from KMI's El Paso Tank Farm to their Tucson, Arizona Products Terminal. The ruptured east-west flowing 12-inch EPT Pipeline section (LS-18) was exposed to the atmosphere for approximately 25 feet at the bottom of an Elephant Butte Irrigation District (EBID) drainage ditch.

[5] *In re: Santa Fe Pacific Pipeline Partners, LP,* CPF No. 5-2018-5007S, Safety Order (Aug. 8, 2019) (on file with PHMSA and available at https://primis.phmsa.dot.gov/comm/reports/enforce/CaseDetail_cpf_520185007S.html?nocache=2247).

[6] The Safety Order noted that KMI had already completed certain actions relating to Items 1, 3, 4, 5, 6, 7, and 11 of the NOPSO.

PHMSA's investigation revealed that the Failure was caused by external corrosion underneath tape-wrapped coating and that the corrosion had progressed to the point that the remaining pipe wall thickness could no longer support the internal pipe pressure.[7] The rupture opening, from center, measured 22 inches in length and approximately 4 inches in width.[8]

The rupture at the Anthony Drain canal resulted in an unintentional shutdown of the pipeline due to low suction pressure experienced at the upstream pumps at the El Paso Breakout Station.[9] The pump shutdown occurred at 23:40 MST. KMI's controller did not immediately recognize this event as a pipeline failure and subsequent product release, but instead treated it as an abnormal operating condition (AOC).[10] The AOC was being investigated when an external rupture notification was received by KMI's Orange Control Center (OCC) in Orange, California, at 00:50 MST on December 14, 2018.[11] The OCC, in turn, notified the El Paso Breakout Control Room field controller[12] at 01:01 MST.[13] Following this notification, KMI dispatched personnel to the area and closed manual valves upstream and downstream of the rupture. The downstream valve was closed at 02:05 MST and the upstream valve was closed at 02:08 MST on December 14, 2018.[14] At 01:45 MST that same day, KMI notified the National Response Center (NRC) of a release of gasoline from its 12-inch EPT Pipeline near Anthony, New Mexico.[15]

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

---

[7] *See* Pipeline Safety Violation Report (Violation Report) at Exhibit 1 (Failure Investigation Report).

Item 8 of the Safety Order required that KMI conduct its own Root Cause Failure Analysis (RCFA). KMI initially submitted a RCFA on June 26, 2019, that identified the direct cause of the Failure as external corrosion. An updated RCFA was submitted to PHMSA on January 17, 2020. The updated RCFA resulted in KMI clarifying that the direct/immediate cause of the Failure was external corrosion, but also identified three additional root causes under the updated immediate cause, including inadequate leadership/supervision, inadequate identification and evaluation of loss exposures, and inadequate work standards, which included inadequate procedures, practices, or rules.

[8] *See* Violation Report at Exhibit 1, pg. 2 (picture of the rupture opening taken on Dec. 19, 2018, by PHMSA).

[9] *See* Violation Report at Exhibit 2, KMI Orange Control Center (OCC) Daily Report From 12/14/2018 5:00:00AM To 12/15/2018 5:00:00AM.

[10] *Id.* at 1.

[11] *Id.*

[12] 49 C.F.R. § 195.2 provides, in part: "*Controller* means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility."

[13] *See* Violation Report at Exhibit 3, KMI Chronological Sequence of Events Dec. 13-14, 2018.

[14] *Id.*

[15] NRC Incident Report # 1232949 (on file with PHMSA). According to KMI's Chronological Sequence of Events, the NRC report was filed at 02:58 MST.

1. § 195.583 What must I do to monitor atmospheric corrosion control?

(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows: Onshore pipelines, at least once every 3 calendar years, but not exceeding 39 months…

KMI did not conduct atmospheric corrosion inspections at the required intervals for each onshore pipeline or portion of pipeline that is exposed to the atmosphere at least once every three calendar years, but with intervals not exceeding 39 months. Specifically, prior to January 2018, KMI failed to inspect its 12-inch EPT pipeline where it was exposed to the atmosphere for evidence of atmospheric corrosion at the required intervals.[16]

The LS-18 span was installed in 1964 and traversed the Anthony Drain where it was partially exposed above grade.[17] In its Incident Investigation Summary, KMI admits that the Anthony Drain span was part of the original construction and was "exposed to the atmosphere for approximately 26 feet, portions of which were in contact with the soil or partially buried."[18] Despite the pipeline's exposure to the atmosphere, KMI admitted that "prior to 1/31/2018 atmospheric corrosion inspections were not conducted on a 3-year inspection cycle…."[19]

2. § 195.583 What must I do to monitor atmospheric corrosion control?

(a) . . .
(b) During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

During atmospheric corrosion inspections, KMI failed to give particular attention to pipe at soil-to-air interfaces and under disbonded coatings in violation of § 195.583(b). Prior to the Failure, KMI's Atmospheric Corrosion Inspection procedures, L-O&M 918, *Inspecting for Atmospheric Corrosion,* stated that "[t]he atmospheric corrosion condition of a given site will be visually evaluated and graded … to determine the nature and severity of corrosion. The three grades used to determine the atmospheric condition will be Good, Fair, and Poor."[20]

---

[16] KMI acknowledged in its updated RCFA that "the bottom of the pipe was likely in contact with the soil during its service life." KMI Incident Investigation Summary (Jan. 17, 2020) at 2.

[17] *Id.*

[18] *Id.*

[19] *Id.* at 5.

[20] *See* Violation Report at Exhibit 4, KMI L-O&M 918 *Inspecting for Atmospheric Corrosion,* (Rev. July 11, 2018) at Attachment 1 – Atmospheric Corrosion Inspection Guidelines (on file with PHMSA) (noting that a "Good atmospheric condition grade is defined by: 1.) A coating system that is well bonded and intact and, 2.) Topcoat degradation that is limited to "chalking" and, 3.) Atmospheric corrosion that is limited to minor surface corrosion in flanged areas, nuts, bolts, and areas affected by routine maintenance operations").

In the months leading up to the release, KMI visited the aboveground span of the drainage ditch (the Anthony Drain traverse, the location where the pipeline eventually ruptured) on at least four occasions in 2018, including three atmospheric corrosion inspections and one vegetation clearing project. On January 31, 2018, during an atmospheric corrosion inspection, KMI inspected the span and recorded the crossing condition as "Good."[21] During this inspection, KMI staff was not able to enter the bottom of the canal where the exposed pipe was located due to extreme overgrowth.[22] In February 2018, a ditch/brush clearing project was performed to remove the abundant vegetation around the crossing.[23] On March 8, 2018, during a cathodic protection survey, the span was inspected for atmospheric corrosion, "consisting of visual, touch/feel along the south side and north side of the exposed pipe with special consideration given to the soil-to-air transition zones at both ends of the canal. The majority of the bottom section (6 o' clock position) was not accessible for inspection. No disbonded coating or voids were found."[24] The atmospheric grade was "Good."[25] On March 21, 2018, an additional atmospheric corrosion inspection of the span was conducted and the condition of the crossing was again recorded as "Good."[26]

By not fully examining the pipe at the soil-to-air interface as noted above, the condition of the pipe continued to deteriorate over time until it eventually failed while in-service. The pipeline rupture, caused by external corrosion in the 5 o'clock position (looking downstream) in the area of the soil-to-air interface, had disbonded polyethylene tape coating that contributed to the rapid development of external corrosion anomalies, which grew to an average depth of 42% of the nominal wall thickness.[27] The tape wrap coating deteriorated over time, likely due to exposure to physical elements,[28] and was not previously identified as a threat during the inspections.[29] KMI failed to give particular attention to pipe at soil-to-air interfaces and under disbonded coatings during atmosphere corrosion inspections.

---

[21] *See* Violation Report at Exhibit 5, KMI Annual LOP Inspection Spreadsheet for LS-18 (Dec. 14, 2018) (noting the condition as "Good").

[22] *See* Violation Report at Exhibit 6, KMI Letter "To Whom It May Concern" (Undated) at 1.

[23] *See* Exponent LS-18 Span Map and Soil Analysis (Apr. 15, 2019) at Figure 3 (photograph indicating that personnel conducting the clearing project had the ability to access the partially-buried pipe in the drainage canal).

[24] *See* Violation Report at Exhibit 7, KMI Memo Re: Three Saints Road Release: Berino, New Mexico (Apr. 10, 2019).

[25] *Id.*

[26] Violation Report at Exhibit 5 at 1. (Note: It is unclear if the March 21 inspection was misdated as March 8.)

[27] This concludes the atmospheric conditions in this area are favorable for significant corrosion.

[28] KMI Updated Root Cause Failure Analysis, Incident Investigation Summary at 8. *See also,* Metallurgical Analysis Report.

[29] *Id.* at 9.

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

> **(a) . . .**
> **(g) *What is an information analysis?* In periodically evaluating the integrity of each pipeline segment (paragraph (j) of this section), an operator must analyze all available information about the integrity of the entire pipeline and the consequences of a failure. This information includes:**
> **(1) …**
> **(2) Data gathered through the integrity assessment required under this section;**
> **(3) Data gathered in conjunction with other inspections, tests, surveillance and patrols required by this Part, including, corrosion control monitoring and cathodic protection surveys; …**

KMI failed to periodically evaluate the integrity of each pipeline segment by analyzing all available information about the integrity of the entire pipeline and the consequences of a failure, including data gathered through integrity assessments and data gathered in conjunction with other inspections, tests, surveillance and patrols required by Part 195.[30] KMI acknowledged that it had failed to gather and integrate all available information about the integrity of the SFPP 12-inch EPT Pipeline from various operational departments of the company including Integrity, Corrosion Control, Engineering, and Operations.[31]

For example, in 2008, KMI conducted a close interval survey (CIS) that revealed the pipeline was exposed to the atmosphere.[32] This information – critical to the integrity of the pipeline – was not properly analyzed, as evidenced by the fact that the Corrosion Department was not even aware of the exposed span until approximately ten years later. Further, 2015 metal loss ILI results indicated corrosion anomalies that were consistent with the rupture location, but these anomalies were not further investigated.[33] By not periodically assembling and analyzing the broadest possible range of available information about the integrity of its pipeline, KMI failed to conduct a complete information analysis about the integrity of its pipeline and the consequences of a failure. By failing to integrate the data, KMI did not fully realize the growing external corrosion threat, which eventually caused the line to rupture.

---

[30] This regulation was revised in 2019 after the incident.

[31] *See* KMI Letter to PHMSA Re: Safety Order Items 6-8 (Jan. 17, 2020), at 8 (finding that "[i]nformation regarding the Anthony Drain site had not been transferred/shared amongst all relevant Company departments, including Integrity, Corrosion Control, Engineering and Operations").

[32] Under a previous Consent Agreement (CPF No. 5-2005-5025H), KMI was required to perform close interval surveys (CIS) of all of the Pacific Operations unit hazardous liquid pipeline systems within 10 years. In October 2008, KMI (thru Corrpro) conducted a CIS on the LS-17-18 line that showed a 20' pipe exposure from pipeline inventory 1837+50 to 1837+70. *See* Exhibit 9.

[33] *See* Violation Report at Exhibit 1, pgs. 5-6 (noting that "[t]he reported anomalies were located where … [an] operator [must] pay particular attention when performing inspections").

4. § 195.446 Control room management.

(a) . . .
(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 the following: …

KMI failed to provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities KMI defined for abnormal and emergency operation. Specifically, KMI's controller had inadequate information to recognize this event as a pipeline failure and instead responded to the Failure only as an abnormal operating condition (AOC). The pipeline did not have pressure indications along the pipeline at the lowest elevations, including the Mesilla Valley, the Anthony Drain (Failure site), and in close proximity to the Rio Grande River. Without having pressure indications closer to the lowest elevation points on the pipeline and because of the significant differences in elevations between the existing sensor locations, the controller did not have adequate information to determine whether the pipeline was leaking or had failed at the lower elevations.

On the day of the Failure, pumps shut down on low suction pressure.[34] After the pumps shut down, the controller received three alarms indicating pressure and flow deviations from "normal operating conditions." KMI treated the unplanned shutdown as an AOC and began to investigate the cause.[35] Although actions were initiated by KMI to determine whether a leak had occurred, they were limited to a walk-through of the El Paso Breakout facilities, checking transmitters, and contacting SCADA to determine if communications were an issue.[36] These actions, however, could not have identified the Failure, which occurred at a low elevation.[37] The controller did not have adequate information through instrumentation to know that product was leaking out of the pipeline at this lower elevation. Without the benefit of additional instrumentation on the line to aid in timely detection of a leak, it took external notification from a separate KMI business unit, over an hour later, for KMI to become aware it had a confirmed release.[38]

---

[34] Pumps can shut down for a variety of reasons that are not indicative of a leak, including high temperature, vibration, loss of communication, etc. On the day of the Failure, the El Paso Breakout station pumps shutdown at 23:40 MST and the pumps at the Deming Pump Station went down due to low suction pressure at 23:42 MST. *See* Violation Report at Exhibit 3.

[35] *See* Violation Report at Exhibit 2, at 1.

[36] *See* Violation Report at Exhibit 3.

[37] For example, the transmitter at the discharge station sees only the hydrostatic head of the pipeline segment between the station and the first mountain range to the west. Any potential leaks downstream of that first segment, including those low-lying areas that traverse HCAs or HCA could-affects (i.e., the Anthony Drain canal), would be impossible to detect by the controllers during a shutdown.

[38] *See* Violation Report at Exhibit 3 (indicating the pumps shut down at 23:40 MST on 12/13/18 and a leak was not confirmed until 01:01 MST on 12/14/18).

Controllers require adequate information to carry out their roles and responsibilities regardless of whether or not the pipeline is flowing at the time of a release. Pressure instrumentation placement that accounts for the terrain of the pipeline (e.g., elevation differences) is essential to providing controllers the information necessary to carry out their roles and responsibilities during abnormal and emergency operations.

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) . .**
> **(4)** ***Emergency Flow Restricting Devices (EFRD).*** **If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, consider the following factors—the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain between the pipeline segment and the high consequence area, and benefits expected by reducing the spill size.**

In determining whether an EFRD was needed to protect an HCA in the event of a release, KMI failed to properly consider several factors set forth in § 195.452(i)(4). Specifically, KMI failed to properly evaluate the following factors: 1) the swiftness of leak detection and the pipeline shutdown capabilities; and 2) the volume that could be released. This resulted in KMI conducting its EFRD analysis based on incorrect data.

In June 2018, KMI identified a discrepancy in its valve classifications and noted that the manual valves (Hand Operated Valves - HOV) were mislabeled as remotely operated valves (Motor Operated Valve - MOV) in its EFRD Analysis.[39] Changes to valves (or in this case, incorrect valve classifications) directly impact several of the factors operators must consider to determine if an EFRD is needed to protect an HCA in the event of a release, including swiftness of leak detection and release volume. When KMI realized it had misclassified valves in its previous EFRD analysis – thus rendering it inaccurate – it should have performed a new analysis that properly considered all the factors set forth in § 195.452(i)(4).

Although KMI contends that there was no material impact to its previous EFRD analysis because even if it had used the correct valve classifications, the data would not have justified installation of an EFRD, this is not what the regulation requires. Section 195.452(i)(4) mandates that operators undergo an analysis that considers certain factors to determine if an EFRD is needed. Operators need only install EFRDS *if* this analysis concludes that one (or more) is needed to

[39] KMI Letter to PHMSA Re: Response to Request for Specific Information (Feb. 14, 2020) at 4. KMI corrected the misclassifications in November 2018.

protect an HCA in the event of a release. In this case, KMI failed to make this determination based on all the required risk factors using accurate information. An EFRD analysis based on missing and incorrect data cannot be relied upon to produce an accurate and sound determination regarding whether EFRDs are needed to protect HCAs in the event of a release.

6. § 195.452 Pipeline integrity management in high consequence areas.

> **(a) . . .**
> **(j) *What is a continual process of evaluation and assessment to maintain a pipeline's integrity?***
> **(1) . . .**
> **(2) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure pipeline integrity. An operator must base the frequency of evaluation on risk factors specific to its pipeline, including the factors specified in paragraph (e) of this section. The evaluation must consider the results of the baseline and periodic integrity assessments, information analysis (paragraph (g) of this section), and decisions about remediation, and preventive and mitigative actions (paragraphs (h) and (i) of this section).**

Prior to the release, KMI failed to conduct a periodic evaluation as frequently as needed to assure pipeline integrity. Specifically, KMI failed to base the frequency of the inspection interval for its LS 17-18 El Paso to Deming pipeline segment on several risk factors set forth in § 195.452(e), including operating stress level, pipe size, manufacturing information, and coating type. KMI's risk analysis for this segment failed to properly consider 1) an operating pressure at a relatively high SMYS level; 2) pipe wall thickness (0.188 inch; low safety margin to withstand rupture should metal loss occur); and 3) type and quality of pipe coating (disbonded coating could result in accelerated external corrosion).[40] These risk factors should have prompted KMI to establish a shorter inspection interval for this pipeline segment because they indicated a likelihood of enhanced corrosion growth rates. In its updated RCFA, KMI acknowledged that one of the basic causes of the Failure was the company's failure to inspect the line on a shorter interval.[41]

After the release, KMI's Pipeline Integrity group initiated a program to reduce integrity assessment intervals on pipelines with a nominal wall thickness of less than 0.200 inches to a maximum 3-year interval.

7. § 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?***

[40] 49 C.F.R. § 195.452(e) and Appendix C to Part 195.

[41] *See* KMI Letter to PHMSA Re: Safety Order Items 6-8 (Jan. 17, 2020) at 10 (stating that "[g]iven the accelerated growth rate that was experienced at the Anthony Drain, KM agrees that the ILI intervals should be more frequent than 5 years").

(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.

KMI failed to properly evaluate the capability of its leak detection means and modify it, as necessary, to protect high consequence areas in violation of §195.452(i)(3). Specifically, in March 2014, KMI prepared a Leak Detection Analysis (LDA) addressing the factors set forth in §195.452(i)(3).[42] In evaluating the swiftness of leak detection, the company noted that "given a leak size of 50%, KM has the ability to detect/shut down the LS-17-18 El Paso to Deming pipeline in 5 minutes and the ability to isolate it in 10 minutes."[43] The combined time of 15 minutes to detect and isolate a leak, however, was based only on the closure of emergency flow restricting devices (EFRDs).[44] The LDA did not account for the closure of manually-operated valves that were present on the line[45] and can take considerably longer to close.[46]

In the company's EFRD Analysis, KMI noted that manual valves remain open in these simulations.[47] In order to isolate certain segments on the line, however, KMI would have needed to close two manually-operated valves (e.g., the Failure site). In fact, on the El Paso to Deming segment, there were eight manually-operated valves and zero EFRDs on the line.[48] KMI's Integrity Management Plan notes that "[t]his [15-minute response time] is a starting point that can be refined on a line segment by line segment basis during leak detection."[49]

Under section 3, "Desired Capabilities and Improvements," the LDA did not suggest any leak detection system enhancements to meet the Section 2.3 Response Basis of 15 minutes.[50] As

---

[42] *See* KMI Letter to PHMSA Re: Response to Request for Specific Information (Feb. 14, 2020) at 6-8 and Attachments E and F (on file with PHMSA).

[43] *Id.* at 7.

[44] *See* § 195.450 (defining EFRDs as remote-controlled valves or check valves).

[45] KMI Letter to PHMSA Re: Response to Request for Specific Information (Feb. 14, 2020) at 7.

[46] *See* KMI Letter to PHMSA Re: Response to Request for Specific Information (Feb. 14, 2020) at Attachment E, Section 2.3, (noting that mechanisms available for isolating a leak included "human assisted valve closure").

[47] *Id.* at 3.

[48] *See* Violation Report at Exhibit 8, Valve Graphs, Attachment H to KMI RCFA. There are two EFRDs at the stations.

[49] KMI IMP Section 4, High Consequence Areas (Rev. Jan. 2, 2018) at Section 3.1.3 *Rupture Volume Calculations.*

[50] KMI Letter to PHMSA Re: Response to Request for Specific Information (Feb. 14, 2020) at Attachment E, Section 3.

noted above, the 15-minute response time was inaccurate because it only accounted for EFRDs on a line with manually-operated valves. The LDA also noted KMI did not have a leak detection system for transient operations, despite operating under transient conditions 10% of the time.[51] By not fully evaluating the swiftness of leak detection on its line, KMI did not identify necessary modifications for its system, such as adding pressure sensors or flow meters, to protect HCAs.[52] The consequences of KMI's inactions were exposed on the day of the Failure. From the time the pumps shut down, it took KMI approximately 2 hours and 28 minutes to isolate the leak site via closure of manual block valves upstream and downstream of the rupture.

KMI also failed to consider the location of nearest response personnel in evaluating the capability of its leak detection means. In its LDA, KMI erroneously noted response personnel were located in Mission Valley with associated maximum travel time of five minutes.[53] In actuality, the location of the nearest response personnel was a maximum travel time of 2.5 hours from El Paso and 2 hours from Tucson.[54] Although its LDA did not take credit for any perceived benefit provided by proximity to response personnel, KMI was required to consider the accurate location(s) of the nearest response personnel in evaluating its leak detection means pursuant to § 195.452(i)(3) and failed to do so.

In sum, KMI failed to evaluate the capability of its leak detection means and modify it, as necessary, to protect HCAs because KMI's LDA was flawed and never corrected.[55] After the Failure, KMI initiated an updated LDA using correct metrics pursuant to the terms of the Safety Order.

Proposed Civil Penalty

Under 49 U.S.C. § 60122 and 49 CFR § 190.223, you are subject to a civil penalty not to 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. For violation occurring on or after November 2, 2015 and before November 27, 2018, the

[51] *Id.,* at Attachment E, Section 2.3.

[52] At the time of the Failure, there is not a single pressure transmitter, flow meter, or EFRD anywhere on the El Paso to Deming pipeline outside of the pump stations.

[53] *See* KMI Letter to PHMSA Re: Response to Request for Specific Information (Feb. 14, 2020) at Attachment E, Section 2.4.

[54] *Id.* at 5.

[55] Integrity management regulations are performance-based standards that are ongoing in nature. Common sense requires that a performance obligation to evaluate leak detection means, and modify it as necessary to protect HCAs, applies until the evaluation is correctly performed using accurate information.

maximum penalty may not exceed $209,002 per violation per day, with a maximum penalty not to exceed $2,090,022.

We have reviewed the circumstances and supporting documentation involved in the above probable violations and recommend that you be preliminarily assessed a civil penalty of $2,231,779 as follows:

Item number	Penalty
1	$ 46,600
2	$ 52,500
3	$ 2,132,679

Warning Items

With respect to Items 6 and 7, PHMSA reviewed the circumstances and supporting documents involved in this case and has decided not to conduct additional enforcement action or penalty assessment proceedings at this time. Thank you for taking steps to promptly correct these items. Failure to do so may result in additional enforcement action.

Proposed Compliance Order

With respect to Items 3, 4 and 5, pursuant to 49 U.S.C. § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to KMI. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

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 the receipt of this Notice, you have 30 days to submit written comments, or request a hearing under 49 CFR § 190.211. 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 the receipt of this Notice. This period may be extended by written request for good cause.

In your correspondence on this matter, please refer to **CPF 5-2021-022-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: 2021.05.12 10:19:04 -06'00'

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

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

cc: PHP-60 Compliance Registry
PHP-500 R. Reineke, H. Flaherty (#18-139725)

PROPOSED COMPLIANCE ORDER

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

A. In regard to Item 3 of the Notice pertaining to the failure to periodically evaluate the integrity of each pipeline segment by analyzing all available information about the integrity of the entire pipeline and the consequences of a failure, including data gathered through integrity assessments and data gathered in conjunction with other inspections, tests, surveillance and patrols required by Part 195, KMI must complete annual interim reviews of its Data Integration Program to ensure compliance with the requirements set forth in § 195.452(g). This review must be performed by the Managers of Pipeline Integrity, Corrosion Control, Engineering, and Operations. KMI must revise its Integrity Management Plan to include this requirement and must implement it within 90 days of receipt of the Final Order.

B. In regard to Item 4 of the Notice pertaining to the failure to provide its controllers with the information, tools, processes and procedures necessary for the controllers to carry out the roles and responsibilities KMI defined for its controllers under abnormal operations in L-O&M 1101 – Section 3.8(f), KMI must complete annual interim reviews of its L-O&M 1101 – Sections 3.8 and 3.9 to ensure compliance with the requirements set forth in § 195.446(c). This review must be performed by the Control Room Manager and his/her supervisor. KMI must revise its L-O&M procedures to include this requirement and must implement it within 90 days of receipt of the Final Order.

C. In regard to Item 5 of the Notice pertaining to the failure to determine if an Emergency Flow Restricting Device (EFRD) is needed on a pipeline segment to protect HCAs, KMI must revise its L-O&M procedures to ensure its EFRD analyses include consideration of accurate information and all the relevant risk factors, including, but not limited to, those set forth in § 195.452(i)(4). KMI must revise its L-O&M procedures to include these requirements and must implement the procedures within 90 days of receipt of the Final Order. It is also recommended, but not ordered, that KMI implement similar procedures for its Leak Detection Analyses under § 195.452(i)(3).

D. It is requested (not mandated) that KMI maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to the 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.