# NOTICE OF PROBABLE VIOLATION
# PROPOSED CIVIL PENALTY
# and
# PROPOSED COMPLIANCE ORDER

**CERTIFIED MAIL - RETURN RECEIPT REQUESTED**

July 21, 2016

Mr. Gary Buchler
El Paso Natural Gas Company
1001 Louisiana Street
Houston, TX 77002-5089

**CPF 4-2016-1005**

Dear Gary Buchler:

From November 19, 2013 through August 22, 2014, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), pursuant to Chapter 601 of 49 United States Code inspected the El Paso Natural Gas West-North (EPNG) pipeline system records and facilities located in Arizona, New Mexico and Texas.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

**1. §191.5 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.**

EPNG failed to give notice at the earliest practical moment following discovery of each incident as defined in §191.3.

PHMSA reviewed the incident reports for the years 2010-2013 for Inspection System #1720. There were 8 eight reports for this time period. Incident #20110308-16140 in PHMSA Unit 15144 exceeded the notification period of 2 hours. The NRC notification was made 4 hours and 45 minutes following the incident.

2. **§192.459 External corrosion control: Examination of buried pipeline when exposed. Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under Secs. 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion.**

EPNG failed to perform a visual examination on the segment of exposed buried pipeline (Line 1104) searching for evidence of deteriorated coating and/or external corrosion.

Kinder Morgan O&M Procedure 918 *Inspecting for Atmospheric Corrosion*, section 3.2. *Atmospheric Corrosion Monitoring and Inspection Frequency* states,

> *"Buried or submerged pipe that has become exposed to the atmosphere (e.g. by erosion, changing water levels) must be initially inspected and documented on* ***O&M Form OM200-02 – Pipeline Examination Report****, then inspected for evidence of atmospheric corrosion according to the frequencies required by this section while the pipe is exposed…"*

Work Order #12-4965319 provided by EPNG was for a patrol conducted on 1/18/2013. Line 1104 had been exposed by runoff waters following a rainstorm. The patrol record had a photo attached showing the exposure. There was a follow-up WO #13-319519 created, but no form OM200-02 was found documenting the inspection (i.e. visual examination) was performed prior to the reburial of the pipeline.

A visual examination of the coating on the exposed portion of Line 1104 was not performed.

**3. §192.463 External corrosion control: Cathodic protection.**

**(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.**

EPNG did not provide a level of cathodic protection (CP) on Line 1300 that complies with the applicable criteria contained in Appendix D of Part 192.

PHMSA reviewed the CP Survey records for Line 1300 Plains to San Juan, MP 53 0+00 through MP 236 0+00. EPNG identified the section of pipeline between MP 53 0+00 to MP 122 0+00 as being protected by applying the 100 mV polarization decay criteria. The annual surveys were reviewed and indicate the protection was below the level of CP that complies with the applicable criteria. Over the period 2012 through 2014, thirty-seven (37) test points had P/S reads that did not meet the 100 mV polarization shift.

**4. §192.465 External corrosion control: Monitoring.**

**(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.**

EPNG failed to test each pipeline that is under cathodic protection at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection met the requirements of §192.463.

Kinder Morgan Procedure O&M 903 *External Corrosion Control for Buried or Submerged Pipelines*, section 3.4 *CP Surveys, Monitoring and Adjustments*, sub-section 3.4.1 *Pipe-to-Soil Surveys* states,

> *"Measure pipe-to-soil readings at least once each calendar year, not to exceed 15 months at all established test points on all pipelines and appurtenances needed to meet the applicable criteria. Increase inspection frequency when conditions warrant."*

PHMSA reviewed EPNG Annual Cathodic Protection Survey records for inspection system #1720 for the years 2011 through 2014. The review identified the failure of EPNG

to perform the annual surveys on Lines 1104, 1112, 1113, 1208, 2134, the Dutch Flat Compressor Station underground piping located in unit 55334 (Topock Area ACC) and Line 1300 – Roswell at MP 59 0+00 within the required 15-month interval. The Line 1300 survey also skipped the calendar year 2012. The survey dates were as follows:

Line 1104 5/14-21/2012 through 9/1-4/2013,
Line 1112 5/21-24/2012 through 9/5/2013,
Line 1113 5/21-24/2012 through 9/5/2013,
Line 1208 5/21-23/2012 through 9/5/2013,
Line 2134 5/17/2012 through 9/4/2013, and
Line 1300 8/28/2011 through 7/28/2013

In each instance, the 15-month interval was exceeded.

**5. §192.475 Internal corrosion control: General.**

**(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found-**

**(1) The adjacent pipe must be investigated to determine the extent of internal corrosion:**

**(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192,489; and,**

**(3) Steps must be taken to minimize the internal corrosion.**

EPNG failed to inspect the internal surface of a section of a cut out pipe for evidence of internal corrosion as required by §192.475(b). The Operator was unable to locate and provide records to verify that the internal pipe surface inspection was performed.

Kinder Morgan Procedure O&M 906 *Internal Corrosion Control*, section 3.6 *Internal Corrosion Inspection - Pipeline Repairs* states,

> *"Whenever any pipe is removed from a pipeline for any reason, inspect the internal surface for evidence of corrosion".*

When reviewing Project AFE 63171 involving the excavation, inspection and recondition of 420 feet of Line 3201, the PHMSA inspector learned EPNG observed extensive lamination during the UT wall thickness survey. As a result, EPNG decided to cut out and replaced 41 feet of pipe. A review of the Pipeline Examination Report – IMP (Form OM200-02) revealed EPNG marked "N/A – Inside Surface of Pipe Not Exposed". PHMSA raised this question and EPNG personnel stated the replacement of pipe project was under AFE 91222. Upon review of Project AFE91222, PHMSA found the Pipeline Examination Report marked "N/A – Inside Surface of Pipe Not Exposed".

EPNG stated they would investigate further to locate records. On 7/7/2014, EPNG provided a corrected Pipeline Examination Report along with the qualification records for

the employee who was said to have performed internal inspection. When the PHMSA inspector questioned the revised form OM200-02IMP, EPNG personnel stated the form was corrected after the PHMSA inspector brought it their attention. EPNG also provided a signed affidavit of an employee dated 7/18/2014 indicating he performed an internal inspection, after the PHMSA inspection.

**6. §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 one 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.**

**§192.736 Compressor stations: Gas detection.**

**(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests.**

EPNG failed to follow procedures and maintain the gas detection and alarm equipment at San Juan compressor station to function properly as required by §192.736(c) and Kinder Morgan Engineering Design Manual E0200 *Compression*.

Kinder Morgan Engineering Design Manual Procedure E0200 *Compression*, section 17.1 *Gas Detectors* states,

> *"Gas detectors with high and low alarm set points shall be installed in all compressor buildings and in all turbine engine enclosures. The low set point shall be in conformance with Company O&M Procedure 550 - Testing Gas and Fire Detection Systems. This alarm shall provide a visual and audible warning inside the compressor building. To warn personnel approaching the compressor building, visual alarm(s) shall be installed outside the building or enclosure consisting of a minimum of two strobe lights, one each on opposite corners of the building, located so that at least one light is clearly visible from all building entrances..."*

Kinder Morgan Procedure O&M 550 *Testing Gas and Fire Detection Systems*, section 2 *Scope* states,

> *"This procedure outlines minimum requirements for calibrating and testing gas and fire detection equipment installed at Company-owned and/or Company-operated facilities."*

On June 18, 2014, the PHMSA inspector randomly selected one detector at the San Juan Compressor Station building for the field test. During the test, the gas detector was activated by applying a known concentration of gas in air to the respective sensor. An emergency shut-down alarm was acknowledged at the control room. However, the gas detector failed to initiate the visual alarm system (strobe lights) inside and outside of the building. The visual alarm system (strobe lights) was found not operational.

**7. §192.707 Line markers for mains and transmission lines.**

**(a) Buried pipelines. Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:**

**(1) At each crossing of a public road and railroad; and**

**(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.**

EPNG failed to place and maintain pipeline markers as close as practical over each buried transmission line at each crossing of a public road as required by §192.707(a)(1).

Kinder Morgan Procedure O&M 205 *Pipeline Markers and Cover*, section 3.1.1 *Buried Pipelines*, paragraph 3.1.1.2 *All Buried Pipelines (except as covered in 3.1.1.3 Alternative MAOP, Waiver, or Special Permit pipelines) s*tates,

> *"After verification of pipeline location, place line markers as close as practical over each buried pipeline, on each side of the edge of public roads, railroads, and highway rights-of-way. Consider placing additional signs in areas where third party damage to the pipe is possible…"*

The PHMSA representative noticed line markers on Line 2121 within the median of Marina Road were not installed where the pipeline crosses underneath Hualapai Drive and Oliver Drive inside Bullhead City limits.

**8. §192.735 Compressor stations: Storage of combustible materials.**

**(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.**

EPNG failed to store a large quantity of foam cleaning pigs (flammable/combustible materials) a safe distance from the compressor building.

The Kinder Morgan Procedure O&M 119 *Flammable and Combustible Liquid Storage*, section 3.4.4 *Storage in Compressor Buildings* states,

*"Flammable or combustible materials in quantities beyond those required for a day's use or other than those normally used in compressor buildings shall not be stored in compressor buildings."*

During the field inspection at the Williams Compressor Station, the PHMSA representative found a large quantity of foam cleaning pigs stored inside the C Plant Building. The C Plant Building was the active compressor unit at the time of the inspection. The foam cleaning pigs are flammable combustible materials.

EPNG Flagstaff personnel promptly moved the foam pigs out of the C Plant Building during the week of July 21, 2014.

**9. §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-**

**(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);**

EPNG failed to demonstrate the Relief Valve on the Auxiliary Generator at the Roswell Station was set at the correct pressure.

Kinder Morgan Procedure O&M 703 *Pressure Limiting and Relief Devices and Inspections*, section 3.1 *MAOP, MAEP, and Set Points* states,

*"Each facility shall include adequate overpressure protection in its original design, including:*

- *MAOP documentation*
- *Overpressure protection equipment and associated documentation*
- *Set points for each device…"*

On July 23, 2014, the PHMSA inspector randomly selected a first cut fuel relief valve at the Roswell Station to verify the set point in the field. According to Kinder Morgan's last test on 8/13/2013, the relief valve #0043 set point was left at 178 psig. During the field inspection, the PHMSA inspector observed the relief valve fail to relieve pressure at 200 psig. As a result, Kinder Morgan personnel isolated this relief valve by lock out/tag out.

On July 27, 2014, Kinder Morgan responded via email which stated "As of Friday, July 25, 2014, Lucas Moreno and Michael Bruner rebuilt the pilot then checked the Relief Valve operation twice. Each time, the valve relieved properly at 178 psig. Lock out/tag out was removed and the auxiliary generator was returned to service".

During the meeting with Kinder Morgan representatives on October 16, 2014, Kinder Morgan advised the PHMSA inspectors that relief valve #0043 was installed and set at 178 Psig to protect the downstream MAOP of the line that fed the domestic Camp housing, station units, boiler, and the auxiliary fuel for the station. Around 1985, the housing was demolished and in 2007 a high pressure fuel line was installed to supply the station auxiliary fuel gas. Although both parallel regulators set points changed from 145 psig and 150 psig to 125 psig and 130 psig respectively, the relief valve #0043 set point remained at 178 psig.

**10. §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.**

EPNG failed to determine the necessary capacity of the relief devices at intervals not exceeding 15 months, but at least once each calendar year for the following devices:

1) Kat Generator Fuel Gas at Lincoln 6552 Station (Reference Drawing/Record Number: 1001-0849) – EPNG failed to verify the relief valve orifice ID and the outlet size. As a result, the capacity calculation was found to be inaccurate for the calendar years 2011, 2012 & 2013. EPNG's investigation to this issue was initiated after the PHMSA inspector's findings. This was corrected on 10/14/2014 and the capacity was found adequate.

2) 1st Cut for Generator Fuel at Rio Vista 6577 Station (Reference Drawing/Record Number: 1001-2215) – EPNG failed to provide capacity calculations for the calendar years 2011, 2012 & 2013. EPNG's investigation was initiated after the PHMSA inspector's findings. This was corrected on 10/13/2014 and the capacity was found adequate.

3) Generator Fuel Gas at Bondad 6210 Station (Reference Drawing/Record Number: 1000-8383) – EPNG failed to provide regulator calculated/input capacity calculations for the calendar years 2011, 2012 & 2013. EPNG found and corrected this on 10/15/2014 and the capacity was found adequate.

4) Line 1300/1301 – Women's Correctional Facility –DPC 20596 – MP 331+4669 Regulator 1 Relief Valve 1 at Gallup 6538 Mainline Device (Reference Drawing/Record Number: 1001-2497 & 1001-2498) - EPNG failed to provide capacity calculations for the calendar years 2011 & 2012. Relief valve capacity

summary sheet for 2013 was based on assuming relief valve is series 80 type 81 with orifice ID= 8 and required verification of relief valve data. This issue was verified as a result of PHMSA audit and corrected on 10/14/2014 and the capacity was found adequate.

5) Turbine 2 Expansion Gas at White Rock 6597 Station (Reference Drawing/Record Number: 1000-8405) – EPNG failed to verify the Inlet Pressure and MAOP upstream during calendar years 2011 and 2013. As a result, the capacity calculation was found inaccurate (based on 10/29/2014 report). EPNG did not verify the capacity calculation in 2012. EPNG corrected this on 10/15/2014 and the capacity was found adequate.

**11. §192.805 Qualification program.**
**Each operator shall have and follow a written qualification program. The program shall include provisions to:**
**(a) Identify covered tasks;**

EPNG has failed to develop and include a covered task or tasks in its Operator Qualification Plan for loading, launching, receiving and unloading in-line inspection (ILI) smart tools used to perform integrity assessments to meet the requirements of §192.937(c)(1) and other in-line tools used for cleaning, batching, etc.

Loading, launching, receiving, and unloading in-line tools are covered maintenance tasks and meet the four part test required by §192.801(b). The loading, launching, receiving, and unloading functions of running an ILI tools is performed on a pipeline facility, is an operations and maintenance task, is performed as a requirement of this part within the integrity management requirements, and it affects the operations and integrity of the pipeline.

When the PHMSA inspector inquired about a covered task(s) for loading, launching, receiving and unloading in-line inspection tools, EPNG responded via email and stated Legacy El Paso and Kinder Morgan natural gas pipelines do not have a specific task for launching and receiving in-line inspection tools. EPNG further stated that the company uses a combination of natural gas pipeline operator qualification tasks for in-line tool inspection projects. Subsequently, the PHMSA inspector requested EPNG to provide specific covered tasks that encompass the steps required for pigging operations such as isolating pipeline barrels, relieving pressure, inserting or removing internal devices, pressurizing barrel and launching/receiving internal devices. EPNG identified the following covered tasks:

- *004.01.01: Corrosion Monitoring – Atmospheric, External, and Internal: General;*

- *04.01.02: Corrosion Monitoring – Atmospheric, External, and Internal: Offshore Pipelines;*
- *08.01.01: Locating pipelines;*
- *14.10.01: Line Markers;*
- *14.11.03: Pipeline Shutdown, Startup or Pressure Change; Operating Identified Valve(s);*
- *14.20.01: Valve Maintenance: Inspection & Partial Operation,*
- *14.20.02: Valve Maintenance: Maintenance;*
- *18.01.01: Pressure Regulating, Limiting, & Relief Device – O&M; and*
- *27.01.1: Gas control*.

Upon review, PHMSA inspector learned these tasks do not encompass the training and qualification requirements specific to loading ILI tools, launching, receiving, and unloading these tools from both in-service and out of service lines.

Specifically, 004.01.01, 04.01.02, 08.01.01, 14.10.01, 14.11.03, 14.20.01. 14.20.02, 18.01.01 and 27.01.01 did not encompass those steps required for pigging operations. Specifically they did not have requirements for identifying the procedures, practices, and equipment needed for conducting pigging operations; the identification of associated valves; steps for associated isolation and lockout/tagout (LOTO) procedures (isolating the barrel from pipeline); relieving pressure within the barrel and/or, inserting or removing internal devices into/from the barrel, pressurizing the barrel to pipeline pressures; launching, monitoring, and/or receiving/removing ILI tools; nor realigning all identified valves to normal operations. These covered tasks did not reflect the marked differences in pigging operations on in-service and out-of-service lines such as use of product to propel the ILI tool and specific Abnormal Operating Conditions that individuals performing loading, launching, receiving, and unloading need to be qualified in.

The PHMSA inspector reviewed the Kinder Morgan Procedure O&M 235: *Pigging Operations* (Revised date 2006-01-01), section 4 *Training* which states,

> *"Review this procedure and other relevant procedures before pigging projects. Document all training in the employee's local file"*.

No covered task in The Kinder Morgan Operator Qualification Program Appendix A *Table of Gas Covered Tasks* (Revised date: 4/30/2014) reference procedure O&M 235.

The Kinder Morgan Procedure O&M 916 *In-Line Inspections* does not reference covered task(s) that are necessary for qualification to perform ILI runs.

Also, the PHMSA inspector noted on 4/1/2013, EPNG reported an Abnormal Operation Incident # 201304017437 (EPNG Dimmitt Station unit 2 discharge relief valve event) due to Improper block valve operation during pig launching operation at 5793 Springlake, TX. The root cause investigation performed by EPNG attributed the incident to a lack of knowledge.

**12. §192.805 Qualification program.**

**Each operator shall have and follow a written qualification program. The program shall include provisions to:**

**(b) Ensure through evaluation that individuals performing covered tasks are qualified;**

EPNG failed to ensure through evaluation an employee was qualified to perform a covered task.

The Kinder Morgan OQ Program section 1 Scope, second paragraph states,

> *"…KM's OQ Program is designed to ensure that all individuals working on KM's DOT-regulated pipeline facilities are OQ-qualified to perform specific covered tasks, to document that qualification and to reduce the probability and consequences of incidents and accidents…"*

Also, section 3.1.2 *Initial OQ Qualification* states,

> *"Individual(s) will receive training, as appropriate, in preparation for initial qualification evaluations, as part of KM's training program. Trainees will not be allowed to independently perform covered tasks until qualification evaluations are passed."*

While reviewing records associated with an Encroachment/One Call ticket, the PHMSA inspector observed that EPNG received a line-locate request (ticket #2013500358) on 12/9/2013 with the work start date on 12/11/2013. While installing a water line, the contractor uncovered 2 feet of 30" pipeline. An EPNG employee conducted the visual inspection of the external coating on 12/9/2014. The employee completed Form OM200-02: *Pipeline Examination Report* indicating he visually inspected the coating and found it in good condition. The PHMSA inspector reviewed the qualification records for the individual and found the individual was not qualified to perform this covered task. EPNG failed to ensure through evaluation that the employee was qualified to perform the covered task. The covered task the employee was unqualified for is task 004.01.03 *Visual Inspection of Buried Pipe and Components When Exposed*. EPNG stated that the employee was qualified on covered task 14.09.01: *Inspection: Compliance with Procedures*. When the PHMSA inspector reviewed the "Training Modules" for this covered task, it did not encompass those steps required for the inspection of buried pipe and components when exposed.

According to Kinder Morgan OQ Program Appendix A: *Table of Gas Covered Tasks* (Revised 04/30/2014), covered tasks 04.01.03 references Kinder Morgan Procedures O&M 903: *External Corrosion Control for Buried or Submerged Pipelines*, and O&M 918: *Inspecting for Atmospheric Corrosion*; whereas covered task 14.09.01 references Kinder Morgan Procedures O&M 204: *Construction Near Company Facilities*, Kinder Morgan Construction Inspection Manual *Essential Requirement of the Pipeline Inspector* and C1040: *Unloading, Hauling, and Stringing Materials*.

If aforementioned covered task 004.01.03 was performed by a non-qualified individual, Kinder Morgan's OQ Program Appendix A *Table of Gas Covered Tasks* (revised 04/30/2014) requires a span of control of a one to one. According to the inspection documentations provided by KM, a qualified employee was not present to observe or to direct this individual at the work site.

Proposed Civil Penalty

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $200,000 per violation per day the violation persists up to a maximum of $2,000,000 for a related series of violations. For violations occurring prior to January 4, 2012, the maximum penalty may not exceed $100,000 per violation per day, with a maximum penalty not to exceed $1,000,000 for a related series of violations. The Compliance Officer has reviewed the circumstances and supporting documentation involved in the above probable violations and has recommended that you be preliminarily assessed a civil penalty of $ 110,700 as follows:

| Item number | PENALTY |
|---|---|
| 3 | $ 53,200 |
| 4 | $ 23,700 |
| 10 | $ 33,800 |

Warning Items

With respect to items 1, 2, 5, 6, 7, 8, 9 and 12 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.

Proposed Compliance Order

With respect to items 3, 10, and 11, pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to El Paso Natural Gas Company. 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 Compliance 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). 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.

In your correspondence on this matter, please refer to **CPF 4-2016-1005** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

R. M. Seeley
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration

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

## PROPOSED COMPLIANCE ORDER

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

1. In regard to Item Number 3 of the Notice pertaining to EPNG failing to provide a level of cathodic protection (CP) that complies with the applicable criteria contained in Appendix D of Part 192, EPNG must review and modify appropriate procedures as necessary to ensure compliance with the regulations. EPNG shall perform and document the appropriate tests to show that the protection that is being applied meet one of the applicable criteria.

2. In regard to Item Number 10 of the Notice pertaining to EPNG's failure to diligently verify capacities of relief devices installed on the company pipeline system, EPNG must perform a Survey of the overpressure protection devices currently installed on EPNG's natural gas pipeline system. The survey is to evaluate the overpressure protection devices to collect and/or verify data such as inlet and outlet size, the orifice area and coefficient of actual discharge in order to perform sizing calculations. If deficiencies are observed during the calculation of sizing capacities, EPNG must integrate the findings and verify that the regulator and relief devices installed on the facilities have adequate capacities required by 49 CFR §192.743. If the capacity is found to be insufficient, EPNG must install/modify the equipment to provide the required capacity.

3. In regard to Item Number 11 of the Notice pertaining to EPNG failing to develop and include a covered task or tasks in the Operator Qualification Plan for loading, launching, receiving and unloading ILI smart tools for both in-service and out-of-service pipelines, EPNG must develop a covered task for the ILI process. The covered task must cover the tasks for loading, launching, receiving and unloading ILI smart tools for both in-service and out-of-service pipelines and incorporate them into the OQ Program.

4. Provide PHMSA with documentation that verifies completion of numbers 1 & 2 above within 180 days following the receipt of the Final Order. For number 3, provide PHMSA with documentation verifying completion within 90 days following receipt of the Final Order.

5. It is requested (not mandated) that El Paso Natural Gas Company maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to R. M. Seeley, Director, Southwest 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.