U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
SPECIAL PERMIT

Special Permit Information:

Docket Number:	PHMSA-2016-0007
Requested By:	El Paso Natural Gas Company, L.L.C.
Operator ID#:	4280
Date Requested:	January 11, 2016
Original Issuance Date:	September 1, 2016
Effective Dates:	September 1, 2016 to September 1, 2021
Code Section(s):	49 CFR §§ 192.611(a) and (d), 192.619(a), and 192.5

Grant of Special Permit:

By this Order, subject to the terms and conditions set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS) grants a special permit (PHMSA-2016-0007) from September 1, 2016 to September 1, 2021, to El Paso Natural Gas Company, L.L.C. (EPNG) [1] waiving compliance from 49 Code of Federal Regulations (CFR) §§ 192.611(a) and (d), 192.619(a), and 192.5 for 29 ***special permit segments*** and 6.56 miles of natural gas transmission pipeline as described in Appendix A[2] of this special permit.

I. Special Permit Segment and Special Permit Inspection Area:

States of Arizona, New Mexico, and Texas

On the condition that EPNG complies with the terms and conditions set forth below, this special permit waives compliance from 49 CFR § 192.611(a) for 29 ***special permit segments*** and 6.56 miles of natural gas transmission pipeline as described in Appendix A. This special permit allows EPNG to continue to operate each ***special permit segment*** listed in Appendix A at its current listed maximum allowable operating pressure (MAOP). The Federal pipeline safety

[1] El Paso Natural Gas Company, L.L.C. (EPNG) is owned by Kinder Morgan, Inc.

[2] Appendix A of this special permit lists the pipeline ***special permit segment*** location (County and State), MAOP, class location, diameter, wall thickness, grade, seam type, boundaries, and other attributes.

regulations in 49 CFR § 192.611(a) require natural gas pipeline operators to confirm or revise the MAOP of a pipeline segment after a change in class location.

This special permit applies to the ***special permit segments*** listed in Appendix A. ***Special permit segments*** shall be divided into two (2) categories: ***Type A special permit segments*** and ***Type B special permit segments***.

Type A special permit segments include those ***special permit segments*** where there is a cluster, as described in 49 CFR § 192.5(c), of more than 10 buildings intended for human occupancy in a "class location unit" and for which the MAOP has not been confirmed in accordance with 49 CFR § 192.611(a). ***Type A special permit segments*** must be replaced or pressure tested so that the MAOP is commensurate with the present class location within three (3) years of issuance of this special permit. ***Type A special permit segments***[3] total 0.0 miles of pipe as described in Attachment A.

Type A special permit segments with pipe with integrity issues as determined by Conditions 6(c) and 14 or that have not been pressure tested in accordance with 49 CFR Part 192, Subpart J to 1.25 times MAOP of this special permit must be replaced within two and one-half (2½) years of the grant of this special permit or within two (2) years of assessment finding.

Type B special permit segments include those ***special permit segments*** where there is a cluster, as described in 49 CFR § 192.5(c), of 10 or fewer buildings intended for human occupancy in a "class location unit" and for which the MAOP has not been confirmed in accordance with 49 CFR § 192.611. ***Type B special permit segments***[4] total 6.56 miles of pipe as described in Attachment A.

[3] There are 0.0 miles of ***Type A special permit segments*** and of this total 0.0 miles must be replaced and 0.0 miles must be pressure tested as listed on Attachment A, see Condition 16 for pressure test requirements.

[4] There are 6.56 miles of ***Type B special permit segments*** and 1.38 miles of this total must be pressure tested as listed on Attachment A, see Condition 16 for pressure test requirements. Seven (7) ***Type B special permit segment*** (KM segment numbers 21, 23, 25, 26, 29, 175, and 176) are § 192.619(c) Grandfathered segments and will require pressure testing.

Subsequent to the issuance of this special permit, those ***special permit segments*** that have been pressure tested or replaced such that the MAOP has been made commensurate with the present class location as defined in 49 CFR § 192.611 would no longer be included in this special permit.

Special permit inspection area[5] – is defined as a one (1) mile continuous segment on both sides of the ***special permit segment*** (Type A and Type B) plus the footage in the ***special permit segment***. Appendix A lists the boundaries for the ***special permit inspection area*** associated with each ***special permit segment.*** The EPNG ***special permit inspection area*** totals 63.70 miles of pipe as described in Attachment A.

PHMSA hereby grants this special permit for the pipeline ***special permit segments*** listed in Appendix A based on the findings set forth in the *"Special Permit Analysis and Findings"* document, which can be read in its entirety in Docket No. PHMSA-2016-0007 in the Federal Docket Management System (FDMS) located on the internet at www.Regulations.gov.

II. Conditions:

PHMSA OPS grants this special permit subject to the following conditions:

1) **Maximum Allowable Operating Pressure**: CIG must continue to operate the ***special permit segments*** at or below their existing MAOP as noted in Appendix A.

2) **Integrity Management Program**: EPNG must incorporate the ***special permit inspection areas*** into its written integrity management program (IMP) as a *"covered segment"* in a *"high consequence area (HCA)"* in accordance with 49 CFR § 192.903[6].

3) **Close Interval Surveys**: EPNG must perform a close interval survey (CIS) along the entire

[5] ***Special permit inspection areas*** throughout these conditions include ***special permit segments*** unless specifically defined as not applicable or if the ***special permit segment*** has more stringent conditions.

[6] EPNG is not required to report the mileage included as part of this special permit in its annual report per the requirements of 49 CFR § 191.17, unless it is in a high consequence area.

length of all ***special permit inspection areas***[7] and remediate any areas of inadequate cathodic protection no later than three (3) years after the issuance of this special permit. However, a CIS need not be performed if EPNG has performed a CIS and completed remediation[8] including damaged coating repair along the entire length of all ***special permit inspection areas*** less than seven (7) years[9] prior to the issuance of this special permit. If environmental permitting or right-of-way factors beyond EPNG control should prevent the completion of the CIS within three (3) years from the issuance of this special permit, a CIS and subsequent remediation including coating repair must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the appropriate PHMSA OPS Region Director no later than three (3) months prior to the end of three (3) years after the issuance of this special permit and must receive a "no objection" from the PHMSA OPS Region Director for a delay. CIS remediation activities must be completed within one (1) year of the finding. Any extended evaluation and remediation schedules submitted to PHMSA from EPNG must receive a "no objection" from the appropriate PHMSA OPS Region Director to implement an extended CIS and remediation interval.

4) **Close Interval Surveys – Reassessment Interval**: EPNG must perform a periodic close interval survey (CIS) of the ***special permit inspection areas*** at the applicable reassessment interval(s) for a "covered segment" in accordance with 49 CFR Part 192, Subpart O, for reassessment intervals as contained in 49 CFR §§ 192.937(a) and (b) and 192.939, not to exceed a seven (7) year reassessment interval[10]. CIS data shall be integrated with in-line inspection (ILI) data. Condition 15(b) – Data Integration – gives a complete description of

[7] Each condition that requires CIG to perform an action with respect to the ***special permit inspection areas*** shall also require EPNG to perform that action on all ***special permit segments*** within such areas. ***Type A special permit segments*** that will be replaced within three (3) years of this special permit issuance do not require a CIS.

[8] The terms "remediate" or "remediation" of pipe coating shall include repair of damaged external pipe coating, where required to maintain cathodic protection of the pipeline in accordance with 49 CFR §192.463.

[9] If 49 CFR § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, EPNG may use that reassessment interval instead of seven (7) years.

[10] If 49 CFR § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, EPNG may use that reassessment interval instead of seven (7) years.

data integration information that an operator must maintain for a special permit in the ***special permit inspection areas*** which includes CIS and ILI data. CIS assessments within the reassessment interval are not required to be performed in the same year as ILI reassessments.

5) **<u>Cathodic Protection Reliability Improvement Plan</u>**: EPNG shall implement a plan to improve cathodic protection reliability and perform inspections for stress corrosion cracking (SCC).
   a) Cathodic Protection Reliability Improvement Plan
      i) EPNG must perform a periodic CIS of ***special permit inspection areas*** as part of Condition 4, Close Interval Surveys, with reassessment intervals at an increased frequency, not to exceed a seven (7) year reassessment interval with CIS data integrated with the most-recent in-line inspection data[11];
      ii) EPNG must integrate the most current CIS data with in-line inspection results in the ***special permit inspection area*** in accordance with Condition 15(b) timing requirements;
      iii) Within 90 days of the issuance of this special permit, EPNG must amend applicable sections of its operations and maintenance (O&M) manual(s) to prohibit future use of coating that is known to shield cathodic protection along the entire length of the ***special permit inspection areas***; and
      iv) EPNG must perform a run comparison analysis of in-line inspection results subsequent to the baseline inspection in the ***special permit inspection areas*** to identify areas of external corrosion growth after each new tool run when the same in-line inspection vendor is used for consecutive inspections. Areas with corrosion growth over 30% in depth must be remediated within one (1) year of the finding or direct current voltage gradient (DCVG) survey run to locate problem coating areas within six (6) months of the finding with remediation completed within six (6) months of the DCVG survey.

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[11] If 49 CFR § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, EPNG may use that reassessment interval instead of seven (7) years.

v) Within one (1) year of the issuance of this special permit, EPNG must install cathodic protection remote monitoring units (RMUs) at all impressed current sources directly influencing the ***special permit segments***;

vi) EPNG must configure the RMUs in the ***special permit segments*** with alarms to notify EPNG immediately in the event of any interruption in cathodic protection current output; and

vii) EPNG must respond and correct any interruption in cathodic protection current output immediately (within two (2) working days). If a systemic issue is present, then EPNG must investigate and remediate the problem within one (1) month or less or EPNG must receive a "no objection" from the appropriate PHMSA OPS Region Director for issues that require longer to remediate.

b) Stress Corrosion Cracking Inspections

i) EPNG must review historical records to determine if SCC inspections have been performed in the ***special permit segments*** and from these inspections evaluate the threat of stress-corrosion cracking as part of the SCCDA Pre-Assessment Step in Condition 6(a).

ii) EPNG must perform magnetic particle inspection on any pipe (with the exception of pipe coated with fusion-bonded or liquid-applied epoxy coatings, which are not at risk for SCC) excavated in the ***special permit inspection areas*** to evaluate the pipe for SCC where disbonded coating is removed in order to perform the inspection.

6) **Stress Corrosion Cracking Direct Assessment**: EPNG must evaluate pipelines along the entire length of the ***special permit inspection areas*** for SCC as follows:

a) EPNG must perform a stress corrosion cracking direct assessment (SCCDA) or other appropriate assessment method for SCC [such as pressure test or in-line inspection (ILI) with a crack detection tool] of pipelines along the entire length of all ***special permit inspection areas*** according to the requirements of 49 CFR § 192.929 and/or NACE SP 0204-2008 no later than three (3) years after of the issuance of this special permit. The SCCDA or other approved method must address high pH SCC and near neutral pH SCC. The SCCDA Pre-Assessment Step will include the results of all close-interval surveys and coating surveys required in Conditions 3, 4, and 5.

i) If environmental permitting or right-of-way factors beyond EPNG control prevent the completion of the SCCDA survey and remediation within three (3) years from the issuance of this special permit, a SCCDA and remediation must be performed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the appropriate PHMSA OPS Region Director no later than three (3) months prior to the end of three (3) years after the issuance of this special permit and must receive a "no objection" from the PHMSA OPS Region Director for a delay.

ii) EPNG may eliminate this Condition 6(a), provided EPNG provides an engineering assessment showing that the pipeline does not meet the criteria for either near neutral or high pH SCC in accordance with the applicable edition of the American Society of Mechanical Engineers Standard B31.8S, *"Managing System Integrity of Gas Pipelines"* (ASME B31.8S), Appendix A3, or NACE SP 0204-2008, "*Stress Corrosion Cracking (SCC) Direct Assessment Methodology"*, Section 1.2.1.1 and 1.2.2.

iii) A SCCDA need not be performed if EPNG has performed a SCCDA of pipelines along the entire length of the ***special permit inspection areas*** within the timeframe for SCCDA re-assessments specified in 49 CFR Part 192, Subpart O, not to exceed seven (7) years[12] prior to the issuance of this special permit.

b) If the SCCDA required in Condition 6(a) demonstrates SCC, EPNG must directly examine pipe in the ***special permit inspection areas*** for SCC using an accepted industry detection practice, such as dry or wet magnetic particle tests, anytime the pipelines are exposed for any reason, including damage prevention activities. Poor coating is coating losing adhesion to the pipe which is shown by falling off the pipe,

[12] If 49 CFR § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, EPNG may use that reassessment interval instead of seven (7) years.

and/or shields the cathodic protection. EPNG must keep coating records[13] of all excavation locations for the ***special permit inspection areas*** to demonstrate the coating condition.

c) If SCC[14] activity is discovered by any means within the ***special permit inspection area*** in similar pipe and pipe coating vintage [in accordance with 49 CFR § 192.917(e)], or has had an in service or hydrostatic test SCC failure or leak; the ***special permit segment*** must be further assessed and mitigated, using one of the following methods, within one (1) year of finding SCC:

  i) Hydrostatic test program

    A. The SCC hydrostatic test program must be performed at a reassessment interval no greater than seven (7) calendar years (but may be at a lesser interval in accordance with the results of an engineering critical assessment) in the ***special permit segment***.

    B. If pipe in the ***special permit segment*** leaks or ruptures during a hydrostatic test due to SCC, all pipe in the ***special permit segment*** must be replaced with new pipe within 18 months of the completion of a successful SCC hydrostatic test. A successful SCC hydrostatic test must be completed prior to returning the ***special permit segment*** to operational service.

  ii) Crack detection tool assessment

    A. SCC detection tool must be run in the ***special permit inspection area***,

    B. All SCC[15] cracking found in the ***special permit segment*** must be replaced with new pipe within one (1) year of finding SCC,

  iii) Operating pressure lowered to 60% of the specified minimum yield strength (SMYS),

  iv) Replace all affected pipe to meet 49 CFR § 192.611 in the ***special permit segment***.

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[13] The records must include, at a minimum, a description of the EPNG's detection procedures, records of finding, and mitigation procedures implemented for the excavation.

[14] "SCC" activity shall be defined as over both 10 percent wall thickness depth and 2-inches in length.

[15] "SCC" activity shall be defined as over both 10 percent wall thickness depth and 2-inches in length.

d) If any SCC activity is discovered in the ***special permit inspection area***, EPNG must submit a SCC remediation plan to the appropriate PHMSA OPS Region Director with a copy to the Director, PHMSA OPS Engineering and Research Division no later than 60 days after the finding of SCC:

   i) That meets Condition 6(c), including a SCC remediation/repair plan with SCC characterization and timing, or

   ii) Technical justification that shows that the threat for SCC in the ***special permit segment*** is being addressed.

7) **<u>O&M Manual – In-line Inspections, Close Interval Survey Inspections, and Reassessment Intervals</u>**: EPNG must amend applicable sections of its operations and maintenance (O&M) manual(s) to incorporate the in-line inspection (ILI), close interval inspections (CIS), and reassessment intervals by the appropriate integrity assessment method including both high resolution metal loss and deformation/geometry tools along the entire length of the ***special permit inspection areas*** at a frequency consistent with 49 CFR Part 192, Subpart O, but not to exceed a seven (7) year reassessment interval[16].

8) **<u>In-Line Inspection Initial Assessment</u>**: EPNG must perform integrity assessments along the entire length of the ***special permit inspection areas*** using appropriate assessment methods based on threats identified during the risk assessment process including both high resolution magnetic flux leakage (HR-MFL) and either HR-geometry or HR-deformation tools. If integrity assessments have not been performed within seven (7) years prior to the issuance of this special permit, EPNG must complete initial integrity assessments along the entire length of the ***special permit inspection areas*** within three (3) years of the issuance of this special permit. Subsequent integrity assessments along the entire length of the ***special permit inspection areas*** must conform to the required maximum reassessment intervals specified in 49 CFR § 192.939, but may not exceed a seven (7) year reassessment interval[17].

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[16] If 49 CFR § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, EPNG may use that reassessment interval instead of seven (7) years.

[17] If 49 CFR § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, EPNG may use that reassessment interval instead of seven (7) years.

9) **<u>Integrity Reassessment Intervals</u>**: EPNG must schedule integrity reassessment dates for the entire length of the ***special permit inspection areas*** according to 49 CFR § 192.939 by adding the required time interval to the previous assessment date, but may not exceed a seven (7) year reassessment interval[18].

10) **<u>High Consequence Area Assessments</u>**: EPNG must not let this special permit be a basis for deferring any of its assessments for HCAs in accordance with 49 CFR Part 192, Subpart O.

11) **<u>Annual Reports to PHMSA</u>**: Within three (3) months following the issuance of this special permit and annually[19] thereafter, EPNG must report the following to the appropriate PHMSA OPS Region Director with copies to the Deputy Associate Administrator, PHMSA Field Operations; Deputy Associate Administrator, PHMSA Policy and Programs; Director, PHMSA Engineering and Research Division; and Director, PHMSA Standards and Rulemaking Division:
    a) The number of new residences, other structures intended for human occupancy and public gathering areas built within the special permit segment and also within one (1) mile on either end of the ***special permit segment***.
    b) Any new integrity threats identified during the previous year and the results of any ILI or direct assessments performed (including any un-remediated anomalies over 30% wall loss, cracking found in the pipe body, weld seam or girth welds, and dents with metal loss, cracking or stress riser) during the previous year in the ***special permit inspection segment***.
    c) Any reportable incident or any leak normally indicated on the DOT Annual Report, and all repairs on the pipeline that occurred during the previous year in the ***special permit inspection areas***.

[18] If 49 CFR § 192.939(a) integrity management reassessment interval should change from seven (7) years to some other reassessment interval under eight (8) years, EPNG may use that reassessment interval instead of seven (7) years.

[19] Annual reports must be received by PHMSA by the last day of the month in which the Special Permit is dated. For example, the annual report for a modified Special Permit dated November, 2012, must be received by PHMSA no later than November 30, each year beginning in 2013.

d) Summary report of any fatigue analysis performed on all in-service, non-remediated dents over 6% and with total strain $\leq$ 5%, as required in Condition 13(b).

e) Annual data integration information, as required in Condition 15(b) - Data Integration must be submitted beginning with the 2nd annual report that includes an annual overview of any new threats, or if requested by PHMSA a full information package.

f) Any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.

g) An updated Appendix A reflecting changes in ***Special Permit Segment*** boundaries including extensions, deletions, or modifications.

h) In the first annual report, EPNG must describe the estimated economic benefits of the special permit including both the capital and operational costs avoided from not replacing the pipe and the estimated incremental operational costs of any inspection program requirements of the special permit for the 5-year grant period that are not already being conducted by EPNG through their operational procedures.

i) In the first annual report, EPNG must describe whether the public benefits from energy availability. This should address the benefits of any avoided disruptions as a consequence of pipe replacement and the benefits of maintaining system capacity.

12) **Interference Currents Control**: EPNG must address induced alternating current (AC) from parallel electric transmission lines and other interference issues such as direct current (DC) in the ***special permit inspection areas*** that may affect the pipeline. An induced AC or DC program and remediation plan to protect the pipeline from corrosion caused by stray currents must be in place within one (1) year of the date of this special permit.

a) At least once every seven (7) years not exceeding 90 months, EPNG must perform an engineering analysis on the effectiveness of the AC and DC mitigation measures and must evaluate any AC interference between 20 and 50 Amps per meter squared. In evaluating such interference, EPNG must integrate AC interference data with the most recent ILI results to determine remediation measures. Any AC interference between 20 and 50 Amps per meter squared must be remediated within six (6) months of the finding. If EPNG does not remediate AC interference between 20 and 50

Amps per meter squared, EPNG must provide an engineering justification for not remediating such interference to the appropriate PHMSA OPS Region Director, who may accept or reject the justification and require remediation.

b) In ***special permit inspection areas*** with co-located high voltage alternating current (HVAC) power lines, EPNG must take interference readings (continuous 24 hour recordings) during the calendar quarter of the known or anticipated highest voltage reading. If there are any significant increases to the amount of electricity/current flowing in any co-located high voltage alternating current (HVAC) power lines, such as from additional generation, a voltage up-rating, additional lines, or new or enlarged substations, EPNG must perform an AC mitigation survey along the entire co-located pipeline ***special permit inspection area*** right of way within six (6) months of any such change.

c) Within six (6) months of the engineering analysis, EPNG must remediate any AC interference greater than 50 Amps per meter squared. Remediation means the implementation of performance measures including, but not limited to, additional grounding along the pipeline to reduce interference currents. Any DC interference that results in CP levels that do not meet the requirements of 49 CFR Part 192, Subpart I, must be remediated within six (6) months of this evaluation.

d) If environmental permitting or right-of-way factors "beyond EPNG control" prevent the completion of remediation within six (6) months of the interference evaluation, remediation must be completed as soon as practicable and a letter justifying the delay and providing the anticipated date of completion must be submitted to the appropriate PHMSA OPS Region Director no later than one (1) month prior to the end of the six (6) months completion date. Any extended evaluation and remediation schedules submitted to PHMSA from EPNG must receive a "no objection" from the appropriate PHMSA OPS Region Director.

13) **Anomaly Evaluation and Repair**:

a) **General**: EPNG must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs and document and justify the values used. EPNG_must demonstrate ILI Tool tolerance accuracy for each ILI Tool run by usage of calibration excavations and unity plots that demonstrate ILI Tool accuracy to meet the tool accuracy specification provided by the vendor (typical for depth within +10% accuracy for 80% of the time). The unity plots must show: a) actual anomaly depth versus predicted depth and b) actual failure pressure/MAOP versus predicted failure pressure/MAOP. Discovery date must be within 120 days of an ILI Tool run for each type ILI Tool (HR-geometry, HR-deformation, or HR-MFL).

i) ILI tool evaluations for metal loss must use "6t x 6t" interaction criteria (or more conservative criteria) for determining anomaly failure pressures and remediation response timing with *"6t"* being pipe wall thickness times six.

b) **Dents**: EPNG must repair dents in the ***special permit segment*** and ***special permit inspection area*** in accordance with 49 CFR § 192.933 if it is located in a HCA and in accordance with 49 CFR §§ 192.933(a)-(c) repair criteria and "Table 1 – Special Requirements for Scheduling Remediation" if it is not located in an HCA.

Table 1 – Special Requirements for Scheduling Remediation

Defect Type	**Orientation**	**Required Response Special Permit Segment**	**Required Response Special Permit Inspection Area**
Dent Associated with Cracks or Stress Risers	Top or Bottom	Immediate	Immediate
Dent Associated with Metal Loss	Top or Bottom	1 Year Scheduled	2 Year Scheduled
Plain Dent > 6 % OD Deep or that exhibits total strain > 5 %	Top	1 Year Scheduled	2 Year Scheduled
Plain Dent > 2% OD Deep Associated with Girth or Seam Weld	Top or Bottom	1 Year Scheduled	2 Year Scheduled
Plain Dent > 6 % OD Deep and that exhibits total strain ≤ 5 %	Top or Bottom	Monitored	Monitored
Plain Dent ≤ 2% OD Deep Associated with Girth or Seam Weld	Top or Bottom	Monitored	Monitored
Definitions			

1. Plain Dent – Dent without metal loss, crack or stress riser.
2. Immediate Response – Reduce pressure to 80% of recent maximum pressure. Immediate dents require an immediate pressure reduction and / or restriction and examination and remediation as required in conformance with EPNG requirements within five (5) calendar days from the date of discovery. If the response schedule cannot be met, a technical justification must be prepared that explains the reasons why the schedule cannot be met and indicate how the changed schedule will not jeopardize public safety. Any extended response schedules must be submitted to PHMSA from EPNG within 14 days of pressure reduction after discovery and must receive a "no objection" from the appropriate PHMSA OPS Region Director.
3. Scheduled Response – Schedule excavation within an appropriate time frame based on the opinion of the SME (not to exceed 365 days for ***special permit segments*** and 730 days for ***special permit inspection areas***).
4. Monitored – Catalog data for future monitoring.
5. Top – located between 8 o'clock and 4 o'clock positions (upper 2/3 of the pipe).
6. Bottom – located between 4 o'clock and 8 o'clock positions (bottom 1/3 of pipe).

Special permit segments and ***special permit inspection areas*** must have a HR-geometry or HR-deformation tool inspection as part of the initial ILI or these ILI inspections must be completed within two (2) years after issuance of this special permit. All dent repairs must be made in accordance with 49 CFR §§ 192.933(a) through (c) repair criteria and "Table 1 – Special Requirements for Scheduling Remediation" on page 13 of 24. EPNG must conduct the following fatigue analysis of dents in ***special permit segments*** and ***special permit inspection areas:***

i) EPNG must conduct a fatigue analysis of all in-service, non-remediated dents above 6% and with total strain ≤ 5% after each high resolution MFL and high resolution caliper or deformation ILI evaluations. Dent fatigue analysis must include as a minimum the following: gross geometry of dent; orientation of dent; soil cover and type; pressure and temperature; including cycles; and stress and strains caused by terrain. The fatigue analysis must be completed within the time frames in "Table 1 – Special Requirements for Scheduling Remediation" of this special permit.

ii) The overall remaining fatigue life of all in-service, non-remediated dents over 6% and with total strain ≤ 5% must be either twice the designated remaining life of the pipeline or at least 500 years.

c) **Investigation and Repair Criteria**: In-line inspection anomalies in the ***special permit inspection areas*** with a safe pressure less than MAOP (e.g. Failure Pressure Ratio (FPR) < 1.39) or an anomaly depth greater than 80% of pipe wall thickness require an immediate pressure reduction and/or restriction and continuous action until the anomaly is examined, evaluated, and remediated.

d) **Response Time for ILI Results**: EPNG will follow Kinder Morgan O&M Procedure 916 (In-Line Inspections)[20] for excavating, investigating, and remediating anomalies[21] based on ILI data results in accordance with 49 CFR §§ 192.485 and 192.933. EPNG must evaluate ILI data by using either the ASME Standard B31G, "*Manual for Determining the Remaining Strength of Corroded Pipelines*" (ASME B31G), the modified B31G (0.85dL), or R-STRENG for calculating the predicted FPR to determine anomaly responses. .

- ***Special permit segments*** and ***special permit inspection areas***:
  - **Immediate response:** Any anomaly within a ***special permit segment*** and ***special permit inspection areas*** operating up to 72% SMYS that meets either: (1) an FPR equal to or less than 1.1; or (2) an anomaly depth equal to or greater than 80% wall thickness loss.
  - **One-year response:** Any anomaly within a ***special permit segment*** and ***special permit inspection areas*** with original Class 1 location pipe in a Class 3 location (cluster area) operating up to 72% SMYS that meets either: (1) an FPR less than 1.39; or (2) an anomaly depth greater than 40% wall thickness loss.
  - **Monitored response:** Any anomaly within a ***special permit segment*** and ***special permit inspection areas*** with original Class 1 location pipe in a Class 3 location operating up to 72% SMYS that meets both: (1) an FPR equal to or greater than 1.39; or (2) an anomaly depth less than or equal to 40% wall thickness loss.

e) ***Special permit segments*** and ***special permit inspection areas:*** Upon issuance of this special permit, EPNG must implement the repair and remediation of any pipe

[20] The requirements of this Special Permit and 49 CFR §§ 192.485 and 192.933 supersedes Kinder Morgan O&M Procedure 916 (In-Line Inspections).

[21] The timing intervals for dent remediation in non-HCAs are in Condition 6(b).

anomalies or dents that are not in compliance with Condition 13 based upon existing ILI assessment results from the high resolution MFL and geometry/deformation tools used to previously assess pipelines in the ***special permit segments*** and ***special permit inspection areas***. EPNG must review existing ILI assessment results within 18 months from the issuance of this special permit according to the following schedule: 30% of pipelines in the ***special permit segments*** and ***special permit inspection areas*** must be reviewed within six (6) months of the issuance of this Special Permit, 65% of pipelines in the ***special permit segments*** and ***special permit inspection areas*** must be reviewed within 12 months of the issuance this special permit, and 100% of pipelines in the ***special permit segments*** and ***special permit inspection areas*** must be reviewed within 18 months of the issuance of this Special permit. Anomalies and dents discovered during this review must be remediated in accordance with Condition 13 timing requirements.

14) **Pipe Seam Evaluations**:

a) EPNG must identify any pipe in the ***special permit segment*** that may be susceptible to pipe seam issues because of the vintage of the pipe, the manufacturing process of the pipe, or other issues. Once EPNG has identified such issues, EPNG must complete Condition 14(a). If the engineering analysis required in Condition 14(a) reveals that there is a threat to the pipeline, then EPNG must complete all of the applicable condition requirements in Condition 14(a)(ii), (a)(iii), (a)(iv), (a)(v), (a)(vi), (a)(vii), and (a)(viii):

i) EPNG must perform an engineering analysis to determine if there are any pipe seam threats on pipelines located in the ***special permit segment***. This analysis must include the documentation that the processes in 'M Charts' in "*Evaluating the Stability of Manufacturing and Construction Defects in Natural Gas Pipelines*" by Kiefner and Associates updated April 26, 2007, under PHMSA Contract DTFAA-C0SP02120 and Figure 4.2, 'Framework for Evaluation with Path for the Segment Analyzed Highlighted' from TTO-5 "*Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation*" by Michael Baker Jr., and Kiefner and Associates, et. al. under PHMSA

Contract DTRS56-02-D-70036 were utilized along with other relevant materials. If the engineering analysis shows that the pipe seam issues on pipelines located in the ***special permit segment*** are not a threat to the integrity of the pipeline, EPNG does not have to complete Conditions 14(a)(ii) through (vii), but must complete Condition 14(a)(viii) and (ix).

ii) If a 49 CFR Part 192, Subpart J hydrostatic test has not been performed, the ***special permit segments*** must be hydrostatically tested to a minimum pressure of 100 percent SMYS, in accordance with 49 CFR Part 192, Subpart J requirements for eight (8) continuous hours, within two and one-half (2½) years of issuance of this special permit. The hydrostatic test must confirm no systemic issues with the weld seam or pipe. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure[22] experienced to verify that it is not indicative of a systemic issue. The results of this root cause analysis must be reported to the appropriate PHMSA Region Director with a copy to the Director, PHMSA Engineering and Research Division, within 60 days of the failure.

iii) ***Special permit segments*** with low frequency electric resistance welded (LF-ERW) pipe or seam factor below one (1) and a history of leaks or failures without a "spike test" within the s***pecial permit inspection area*** must be pressure tested[23] with a "spike test" within two and one-half (2½) years of the issuance of this special permit.

iv) ***Special permit segments***[24] with pressure tests less than 1.25 times MAOP that may be susceptible to pipe seam issues must be tested with a Subpart J pressure test within two and one-half (2½) years of issuance of this special

[22] A root cause analysis, including metallurgical examination of the pipe, must be performed for any leaks that are removed from the ***special permit segment***.

[23] A root cause analysis, including metallurgical examination of the pipe, must be performed for any pressure test failures or leaks from the ***special permit segment***.

[24] EPNG must implement the replacement of all Type A special permit segments as defined on page 2 of this special permit as noted: "Type A special permit segments with pipe with integrity issues as determined by Conditions 6 and 14 or that have not been pressure tested in accordance with 49 CFR Part 192, Subpart J to 1.25 times MAOP of this special permit must be replaced within two and one-half (2½) years of the grant of this special permit or within two (2) years of assessment finding."

permit or the pipe must be replaced with pipe that meets § 192.619 within two and one-half (2½) years of issuance of this special permit. If the pipe is then commensurate with the Class location in accordance with § 192.611(a)(3)(ii) the segment is no longer part of this Special Permit.

v) If the pipeline in the ***special permit inspection area*** has experienced a seam leak or failure in the last five (5) years and no hydrostatic test meeting the conditions of 49 CFR Part 192, Subpart J was performed after the seam leak or failure, then a hydrostatic test must be performed within two and one-half (2½) years after the issuance of this special permit on the ***special permit segment*** pipeline[25]; or

vi) If the pipeline in any ***special permit segment*** has pipe seam conditions as noted below in (A), (B), or (C), such ***special permit segment*** pipeline shall not be eligible for this special permit:

A) has unknown manufacturing processes without the greater of a 49 CFR Part 192, Subpart J hydrostatic test or a 1.25 times MAOP pressure test, or

B) has low fracture toughness pipe that will not ensure ductile fracture and arrest, or

C) has known manufacturing or construction issues that are unresolved [such as concentrated hard spots, hard heat-affected weld zones, selective seam corrosion, pipe movement that has led to buckling, have had past leak and rupture issues, or any other systemic issues].

vii) If the pipeline in any ***special permit segment*** has a reduced longitudinal joint seam factor, below 1.0, as defined in 49 CFR § 192.113 the ***special permit segment*** pipeline must be replaced.

viii) Pipe in the ***special permit segments*** must have all weld seam or girth weld repairs that have been made by the usage of fittings such as weldolets, threadolets, repair clamps and pipe sleeves removed and replaced with pipe in accordance with 49 CFR Part 192 requirements.

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[25] A root cause analysis, including metallurgical examination of the pipe, must be performed for any pressure test failures or leaks from the ***special permit segment***.

b) EPNG must submit a seam remediation plan for the ***special permit segments*** to the appropriate PHMSA Region Director no later than 30 days after finding a seam leak in the ***special permit segment***:

i) Longitudinal weld seam remediation/repair plan that meets Condition 14(a) and includes either replacement, hydrostatic testing, or in-line inspection (ILI), and timing of the plan not to exceed six (6) months, or

ii) Technical justification that shows that the ***special permit segment*** is not at risk for future longitudinal seam leaks or failures.

15) ***Special Permit Segment*** **Specific Conditions**: EPNG must comply with the following requirements.

a) **Line-of-Sight Markers**: EPNG must install and maintain line-of-sight markings on the pipeline in the ***special permit inspection areas*** except in agricultural areas or large water crossings such as lakes where line-of-sight signage is not practical. Line-of-sight markers must be installed within three (3) months of issuance of this special permit and replaced as necessary by EPNG within 30 days after identification.

b) **Data Integration**: EPNG must maintain data integration of special permit condition findings and remediation in the ***special permit inspection areas***. Data integration must include the following information: Pipe diameter, wall thickness, grade, and seam type; pipe coating; maximum allowable operating pressure (MAOP); class location (including boundaries on aerial photography); high consequence areas (HCAs) (including boundaries on aerial photography); hydrostatic test pressure including any known test failures; casings; any in-service ruptures or leaks; in-line inspection (ILI) survey results including HR-MFL, HR-geometry/caliper or deformation tools; close interval survey (CIS) surveys – most recent; rectifier readings; cathodic protection test point survey readings; AC/DC interference surveys; pipe coating surveys; pipe coating and anomaly evaluations from pipe excavations; stress corrosion cracking (SCC) excavations and findings; and pipe exposures from encroachments. Data integration must be outlined on pipeline route drawings with parallel sections for each integrity category and recent aerial photography (recent photography, within three (3) years of initial filing and every three (3) years thereafter).

i) Data integration documentation and drawings to meet Condition 15(b) must be completed and must be submitted, if requested by PHMSA, beginning with the 2nd annual report of this special permit with four (4) years of prior data.

ii) Data integration must be updated on an annual basis and with at least an annual review of integrity issues to be remediated.

c) **<u>Pipe Properties Testing</u>**: EPNG must test pipe in each ***special permit segment*** that does not meet Condition 16(b) as follows:

i) Develop and implement procedures for conducting non-destructive or destructive tests, examinations, and assessments for ***special permit segments*** without pipe material records within 12 months of issuance of this special permit;

ii) A minimum of two (2) destructive or non-destructive test methods must be performed at an excavation site for each ***special permit segment***. For each ***special permit segment***, EPNG will conduct one (1) non-destructive yield test assessment using TD Williamson test procedures and ball indention methodology[26], or equivalent, and secondly, confirm yield strength through diameter tape measurements. Should non-destructive testing of pipe material properties show that the pipe wall thickness is not within API 5L specification tolerances and the pipe grade is under the strength requirements of API 5L by three (3) KSI or more, then the yield strength of that individual pipe shall be confirmed using destructive test methods or the ***special permit segment*** pipe must be removed within 18 months of issuance of this special permit. Acceptance limits for the diameter tape measurements shall be in accordance with PHMSA Advisory Bulletin ADB-09-01.

iii) Assessments must be made for each unique combination of the following attributes with missing mill test reports (MTRs) or mill inspection reports (i.e. Moody Engineering Reports): wall thicknesses (within 10 percent of the smallest wall thickness in the population), grade, manufacturing process, pipe

[26] Non-destructive assessment method and procedures must be submitted to PHMSA OPS Region Director and PHMSA OPS Director of Engineering and Research Division for review and "no objection."

manufacturing dates (within a two (2) year interval) and construction dates (within a two (2) year interval).

iv) The material properties determined from either destructive or non-destructive tests required by this Condition cannot be used to raise the original grade or specification of the material, which must be based upon the applicable standard referenced in 49 CFR § 192.7.

v) For future ***special permit segments*** with missing MTRs or mill inspection reports, the above methodology shall be applied or EPNG may elect to remove pipe joints for destructive testing[27]. Such testing shall be performed within one (1) year of identification of the new ***special permit segment***.

d) **Pipeline System Flow Reversals**: For long term pipeline system flow reversals exceeding 90 days where either 49 CFR § 192.619(a)(1) or § 192.611 MAOP for class location changes are exceeded[28] in a ***special permit segment***, EPNG shall prepare a written plan that corresponds to those applicable criteria identified in PHMSA Advisory Bulletin (ADB-2014-04), "Guidance for Pipeline Flow Reversals, Product Changes and Conversion of Service" issued on September 18, 2014 (79 FR 56121, Docket PHMSA-2014-0400). The written flow reversal plan must be submitted to the appropriate PHMSA OPS Regional Director with a copy of the plan submitted to the Federal Docket for this special permit at www.regulations.gov. EPNG must receive a "no objection" from the appropriate PHMSA OPS Region Director prior to implementing the pipeline system flow reversal through the ***special permit segment.***

e) **Environmental Assessments and Permits**: EPNG must evaluate the potential environmental consequences and affected resources of any land disturbances and water body crossings needed to implement the special permit conditions for a ***special permit segment*** or a ***special permit inspection area*** prior to the disturbance. If a land disturbance or water body crossings is required, EPNG must obtain and adhere to all applicable (Federal, State, and Local) environmental permit requirements when

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[27] EPNG must prepare a procedure in accordance with Condition 15(c) for material documentation and submit to PHMSA's OPS Region Director for "no objection".

[28] An example of exceedance of 49 CFR § 192.619(a)(1) is a Grandfathered MAOP which has a design factor above 0.72. An example of exceedance of 49 CFR § 192.611 is a Class 1 to 3 location change.

conducting the special permit conditions activity.

16) **Documentation**: EPNG must maintain the following records for each ***special permit segment***:

a) Documentation showing that each ***special permit segment*** has received a 49 CFR § 192.505, Subpart J, hydrostatic test for eight (8) continuous hours and at a minimum pressure of 1.25 times MAOP (1.25 x MAOP). If EPNG does not have hydrostatic test documentation, then:

- ***Type A special permit segments*** must be hydrostatically tested to meet this requirement within two and one-half (2½) years of the issuance of this special permit, and
- ***Type B special permit segments*** must be hydrostatically tested to meet this requirement within three (3) years of the issuance of this special permit.

b) Documentation of mechanical and chemical properties including pipe toughness (mill test reports) showing that the pipe in each ***special permit segment*** meets the wall thickness, yield strength, tensile strength and chemical composition of either the American Petroleum Institute Standard 5L, 5LX or 5LS, *"Specification for Line Pipe"* (API 5L) referenced in the 49 CFR Part 192 code at the time of manufacturing or if pipe was manufactured and placed in-service prior to the inception of 49 CFR Part 192 then the pipe meets the API 5L standard in usage at that time.

c) Documentation of compliance with all the conditions of this special permit must be kept for the applicable life of this special permit for the referenced ***special permit segments*** and ***special permit inspection areas.***

17) **Extension of Special Permit Segments**: PHMSA may extend each original ***Type B special permit segment*** to include contiguous segments of pipeline on either side of the ***Type B special permit segment*** where, following the issuance of this special permit, an increase in population density indicates a change in class location. ***Type A special permit segments*** may not be extended. ***Type B special permit segments*** may not be extended if the extension would redefine the extended segment as a ***Type A special permit segment*** as described in Section I of this special permit. EPNG must:

a) Provide notice to the Director, PHMSA OPS Standards and Rulemaking Division; Director, PHMSA OPS Engineering and Research Division; and appropriate PHMSA OPS Region Director of a requested ***special permit segment or extension***[29] based on actual class location change and include a schedule of inspections, of any anticipated remedial actions and the location of the new request including survey stationing. All requests for a ***special permit segment or extension*** must be submitted in the first nine (9) months of the 49 CFR § 192.611(d) timing limits, and must include data integration (see Condition 15(b)) and information on the potential environmental impacts of the extension to determine whether an environmental assessment is required for the ***special permit segment extension***.

b) Complete all inspections and remediation of the proposed ***special permit segment extension*** to the extent required of the original ***special permit segment***.

c) Comply with all the special permit conditions and limitations included herein to all future ***special permit segments or extensions***.

d) ***New Type A special permit segments*** created following the grant date of this special permit must be replaced or pressure tested so that the MAOP is commensurate with the present class location as defined in 49 CFR § 192.611 within two (2) years of the class location change.

e) Comply with all conditions of this special permit for the contiguous new ***special permit segments or extensions*** required for implementation and certification in accordance with 49 CFR § 192.611(d) timing limits, including submittal of documents to PHMSA required in Condition 18 - Certification.

18) **<u>Certification</u>**: A senior executive officer, vice president or higher, of EPNG must certify in writing the following:

a) EPNG pipeline ***special permit inspection areas*** and ***special permit segments*** meet the conditions described in this special permit,

b) The written manual of O&M procedures (required by § 192.605) for the EPNG pipeline has been updated to include all additional requirements of this special permit;

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[29] For a new ***special permit segment or extension*** to be considered by PHMSA, EPNG must notify the appropriate PHMSA OPS Region Director to determine the need for a draft environmental assessment.

and

c) EPNG has implemented all Conditions as required by this special permit.

EPNG must send the certifications required in Condition 18(a) through (c) with completion date, compliance documentation summary, and the required senior executive signature and date of signature to the PHMSA OPS Associate Administrator with copies to the Deputy Associate Administrator, PHMSA OPS Policy and Programs; appropriate PHMSA OPS Region Director; Director, PHMSA OPS Standards and Rulemaking Division; Director, PHMSA OPS Engineering and Research Division; and to the Federal Register Docket (PHMSA-2016-0007) at www.Regulations.gov within one (1) year of the issuance date of this special permit.

III. Limitations:

PHMSA modifies this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether EPNG has complied with the specified conditions of this special permit.

2) Failure to submit the certifications required by Condition 18 within the time frames specified may result in revocation of this special permit.

3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and require EPNG to comply with the regulatory requirements in 49 CFR § 192.611. As provided in 49 U.S.C. Chapter 601 and 49 CFR Part 190, PHMSA may also issue an enforcement action for failure to comply with this Order. Any work plans and associated schedules shall be automatically incorporated into this order and are enforceable in the same manner.

4) Should PHMSA revoke, suspend, or modify a special permit under 49 CFR § 190.341(h)(1), PHMSA will notify EPNG in writing of the proposed action and provide EPNG an opportunity to show cause why the action should not be taken. In accordance with 49 CFR § 190.341(h)(3), if necessary to avoid the risk of significant harm to persons, property, or the

environment, PHMSA will not give advance notice and will declare the proposed action (revocation, suspension, or modification) immediately effective.

5) The terms and conditions of any corrective action order, compliance order or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit in accordance with 49 CFR § 190.341(h)(4).

6) If EPNG sells, merges, transfers, or otherwise disposes of the assets known as the ***special permit segments*** or the ***special permit segment extension***, EPNG must provide PHMSA with written notice of the transfer within 30 days of the consummation date. In the event of such transfer, PHMSA reserves the right to revoke, suspend, or modify the permit if the transfer constitutes a material change in conditions or circumstances pursuant to 49 CFR § 190.341(h)(1)(ii) or any other circumstances listed under 49 CFR § 190.341(h)(1).

7) PHMSA grants this special permit to limit it to a term of no more than five (5) years from the issuance date. If EPNG elects to seek renewal of this special permit, as modified, EPNG must submit its renewal request at least 180 days prior to expiration of the five (5) year period to the PHMSA Associate Administrator with copies to the Deputy Associate Administrator, PHMSA Policy and Programs; appropriate PHMSA OPS Region Director; Director, PHMSA OPS Standards and Rulemaking Division; and Director, PHMSA OPS Engineering and Research Division. PHMSA will consider requests for a special permit renewal for up to an additional five (5) year period. All requests for a special permit renewal must include a summary report in accordance with the requirements in Condition 11 (Annual Report) above and must demonstrate that the special permit is still consistent with pipeline safety. PHMSA may seek additional information from EPNG prior to granting any request for special permit renewal.

AUTHORITY: 49 U.S.C. 60118 (c)(1) and 49 CFR § 1.97.
Issued in Washington, DC, on September 1, 2016.

Alan K. Mayberry
Acting Associate Administrator for Pipeline Safety

Attachment A: Listing of El Paso Natural Gas Company (EPNG) Special Permit Segments

PHMSA REGION	PHMSA No.	KM No.	State	County	Line Name	Special Permit Segment Stationing (Beginning) MP.- Station	Special Permit Segment Stationing (Ending) MP - Station	Special Permit Segment Type	Special Permit Inspection Area Stationing (Beginning) MP - Station	Special Permit Inspection Area Stationing (Ending) MP - Station	Class (present)	Class (pipe)	HCA	Latest HCA Assessment and Date	Special Permit Inspection Area Length (ft)	Special Permit Segment Length not meeting present Class (ft)	Replace Length (ft)	Pressure Test Length (ft)	Dwellings in length not meeting present Class	Pipe Diameter (in)	MAOP (psig)
WESTERN	1	11	AZ	COCHISE	1100	0428 - 5065	0429 - 1197	B	0427 - 5049	0430 - 786	3	1	NO	N/A	11972.75	1412.75	1412.75	0	1	26	837
WESTERN	2	12	AZ	COCHISE	1100	0430 - 1109	0430 - 4491	B	0429 - 1520	0431 - 4892	3	1	NO	N/A	13941.29	3381.29	3381.29	0	8	26	837
WESTERN	3	13	AZ	COCHISE	1100	0445 - 4824	0446 - 1047	B	0444 - 4626	0447 - 350	3	1	NO	N/A	12016.14	1456.14	1456.14	0	8	26	837
WESTERN	4	15	AZ	PIMA	1100	0471 - 4897	0471 - 5199	B	0470 - 4962	0472 - 5211	3	1	NO	N/A	10861.74	301.74	301.74	0	2	26	809
WESTERN	5	17	AZ	COCHISE	1103	0445 - 4670	0446 - 1038	B	0444 - 4886	0447 - 373	3	1	NO	N/A	12008.51	1448.51	1448.51	0	6	30	837
WESTERN	6	21	AZ	COCONINO	1200	0212 - 3171	0212 - 4534	B	0211 - 3171	0213 - 4531	3	1	NO	N/A	11923.19	1363.19	999.1	364.09	2	24	845
WESTERN	7	22	AZ	COCONINO	1200	0254 - 1614	0254 - 3231	B	0253 - 1702	0255 - 3219	3	1	NO	N/A	12177.06	1617.06	1617.06	0	8	24	845
WESTERN	8	23	AZ	MOHAVE	1200	0380 - 3037	0380 - 4089	B	0379 - 3127	0381 - 4066	2	1	NO	N/A	11612.01	1052.01	0	1052.01	1	24	845
WESTERN	9	24	AZ	COCONINO	1201	0212 - 3143	0212 - 4480	B	0211 - 3143	0213 - 4493	3	1	NO	N/A	11897.01	1337.01	1337.01	0	2	30	845
WESTERN	10	25	AZ	MOHAVE	1201	0380 - 3158	0380 - 4068	B	0379 - 3275	0381 - 4077	2	1	NO	N/A	11470.16	910.16	0	910.16	1	30	845
WESTERN	11	26	AZ	YAVAPAI	1203	0084 - 560	0084 - 1312	B	0083 - 589	0085 - 1334	3	2	NO	N/A	11311.91	751.91	0	751.91	4	20	877
WESTERN	12	27	AZ	COCONINO	1204	0212 - 3472	0212 - 4534	B	0211 - 3472	0213 - 4531	3	1	NO	N/A	11622.1	1062.1	902.1	160	2	34	894
WESTERN	13	28	AZ	COCONINO	1204	0254 - 241	0254 - 2696	B	0253 - 248	0255 - 2885	3	1	NO	N/A	13014.82	2454.82	2454.82	0	6	34	894
WESTERN	14	29	AZ	MOHAVE	1204	0380 - 3074	0380 - 4098	B	0379 - 3177	0381 - 4061	2	1	NO	N/A	11584.02	1024.02	0	1024.02	1	34	894
WESTERN	15	30	AZ	COCONINO	1208	0212 - 3133	0212 - 4540	B	0211 - 3127	0213 - 4531	3	1	NO	N/A	11967.05	1407.05	1094.7	312.35	2	30	845
WESTERN	16	31	AZ	COCONINO	1208	0254 - 1272	0254 - 2644	B	0253 - 1377	0255 - 2974	3	1	NO	N/A	11931.77	1371.77	1371.77	0	4	36	845
SOUTHWEST	17	169	NM	SAN JUAN	1200	0000 - 5193	0001 - 313	B	0000 - 0	0001 - 5593	3	1	NO	N/A	10873.48	400.52	361.54	38.98	2	24	845
SOUTHWEST	18	170	NM	SAN JUAN	1200	0002 - 3859	0002 - 4479	B	0001 - 4270	0004 - 430	3	1	NO	N/A	11180.54	620.54	620.54	0	8	24	845
SOUTHWEST	19	171	NM	SAN JUAN	1201	0002 - 1677	0002 - 4256	B	0001 - 2082	0004 - 206	3	2	NO	N/A	13138.37	2571.93	0	2571.93	9	24	845
SOUTHWEST	20	172	NM	SAN JUAN	1202	0000 - 790	0000 - 835	B	0000 - 0	0001 - 40	3	1	NO	N/A	6115.4	45.7	45.7	0	5	34	894
SOUTHWEST	21	173	NM	MCKINLEY	1300	0386 - 3866	0386 - 4956	B	0385 - 3934	0387 - 4968	3	1	NO	N/A	11649.8	1089.8	1089.8	0	1	30	836
SOUTHWEST	22	174	NM	MCKINLEY	1301	0386 - 3851	0386 - 4958	B	0385 - 3934	0387 - 4960	3	1	NO	N/A	11666.87	1106.87	1106.87	0	1	30	836
SOUTHWEST	23	175	NM	SAN JUAN	3201	0012 - 2973	0012 - 2991	B	0011 - 2973	0013 - 2991	3	2	NO	N/A	10578.3	18.3	0	18.3	5	20	894
SOUTHWEST	24	176	NM	SAN JUAN	3201	0012 - 3231	0012 - 3313	B	0011 - 3231	0013 - 3313	3	2	NO	N/A	10642.15	82.15	0	82.15	4	20	894
SOUTHWEST	25	281	TX	EL PASO	1100	0204 - 3749	0205 - 648	B	0203 - 3740	0206 - 645	3	1	YES	ILI & Caliper - 2010	12740.94	2180.94	2180.94	0	2	26	809
SOUTHWEST	26	282	TX	EL PASO	1103	0204 - 3758	0204 - 4469	B	0203 - 3792	0205 - 4472	3	1	YES	ILI & Caliper - 2010	11270.25	710.25	710.25	0	1	30	809
SOUTHWEST	27	283	TX	EL PASO	1103	0204 - 5009	0205 - 657	B	0203 - 5043	0206 - 549	3	1	YES	ILI & Caliper - 2010	11484.93	924.93	924.93	0	1	30	809
SOUTHWEST	28	284	TX	EL PASO	2000	0816 - 2998	0816 - 4180	B	0815 - 3072	0817 - 4346	3	1	YES	ILI & Caliper - 2009	11742.64	1182.64	1182.64	0	2	30	944
SOUTHWEST	29	285	TX	EL PASO	2000	0816 - 4218	0817 - 468	B	0815 - 4293	0818 - 542	3	1	YES	ILI & Caliper - 2009	11923.23	1363.23	1363.23	0	3	30	944

Special Permit Inspection Area Length	Special Permit Segment Length not meeting present Class	Replace Length	Pressure Test Length	
336,318.43	34,649.33	27,363.43	7,285.90	FOOTAGE
63.70	6.56	5.18	1.38	MILEAGE

LEGEND
ERW - Electric Resistance Weld
FW - Flash Weld
DSAW - Double Submerged Arc Weld
SMLS - Seamless
NLP - Not Like Pipe
NSLP - Non-Susceptible Location or Pipe for SCC
PIR - Potential Impact Radius
MAOP - Maximum Allowable Operating Pressure
MLV - Mainline Valve
HCA - High Consequence Area
SCC[1] - Stress Corrosion Cracking - Bellhole Inspection
SCC[2] - Stress Corrosion Cracking - Hydrotest Failure
SCC[3] - Stress Corrosion Cracking - In-Service Failure
SCC[4] - Stress Corrosion Cracking - Special Permit segment located in upstream compressor segment from SCC indication (within 20 miles), Segment deemed not susceptible to SCC
SSWC - Selective Seam Weld Corrosion
MP5 - Maximum Pressure in 5 Years Preceding 7/1/1970

NOTES
1. When a segment has multiple pipe attributes (test pressure, seam, coating, etc.), the attributes for the weakest pipe element is displayed
2. The actual length of the special permit segment from begin station to end station may be greater than the length not meeting present class due to compliant pipe in the segment.
3. Pipeline stationing subject to change due to station equations, centerline changes, etc.

05/09/2016 rev

Attachment A: Listing of El Paso Natural Gas Company (EPNG) Special Permit Segments

PHMSA No.	KM No.	Test Pressure (psig)	Pipe Design Pressure @ 0.72 (psig)	Pipe Wall Thickness (in)	PIR (ft)	Pipe Grade (psig)	Pipe Seam Type	Pipe Coating	Pipe Installation Date	Distance to MLV Upstream/ Downstream (mi)	Compressor Station Spacing (mi)	MAOP Established per 192.619	Aerial Photography	Material/ Pressure Test Documents	Leak/SCC/SSWC (w/i 20 mi of segment)	Segment Pressure Tested after Leak/SCC/SSWC	In-Line Inspected	MP5 only or MP5 record (to back up 'test')
1	11	1245	872.64	0.303	519	52000	SMLS	COAL TAR ENAMEL	1947	4.6 / 2.1	47	(a)(3)	2012	Y / Y	Leak (8/30/2009)	NO	YES	N/A
2	12	1245	872.64	0.303	519	52000	SMLS	COAL TAR ENAMEL	1947	5.9 / 0.4	47	(a)(3)	2012	Y / Y	Leak (8/30/2009)	NO	YES	N/A
3	13	1179	872.64	0.303	519	52000	SMLS	COAL TAR ENAMEL	1947	4.3 / 0.9	47	(a)(3)	2012	Y / Y		N/A	YES	N/A
4	15	1076	809.28	0.281	510	52000	FW	COAL TAR ENAMEL	1947	24.8 / 7.0	37.8	(a)(3)	2012	Y / Y	Leak (10/17/1981)	YES	YES	N/A
5	17	1196	836.16	0.335	599	52000	DSAW	COAL TAR ENAMEL	1950	4.3 / 0.9	47	(a)(3)	2012	Y / Y	Leak (2/1/2006)	NO	YES	N/A
6	21	MP5	845.52	0.271	481	52000	DSAW	COAL TAR ENAMEL	1950	1.3 / 5.8	50.4	(c)	2012	Y / MP5	Leak (6/30/1995)	NO	YES	YES
7	22	1095	845.52	0.271	481	52000	DSAW	COAL TAR ENAMEL	1950	0.3 / 8.0	36.1	(a)(3)	2012	Y / MP5	Leak (7/10/2003)	YES	YES	YES
8	23	MP5	845.52	0.271	481	52000	DSAW	COAL TAR ENAMEL	1951	5.4 / 4.0	78.5	(c)	2012	Y / MP5	Leak (2/15/2007)	NO	YES	YES
9	24	1120	846.14	0.339	602	52000	DSAW	COAL TAR ENAMEL	1953	1.3 / 5.6	50.4	(a)(3)	2012	Y / Y		N/A	YES	N/A
10	25	MP5	846.14	0.339	602	52000	DSAW	COAL TAR ENAMEL	1953	5.4 / 4.0	78.5	(c)	2012	Y / MP5	Leak (2/17/2005)	NO	YES	YES
11	26	MP5	1052.06	0.281	409	52000	ERW	COAL TAR ENAMEL	1956	3.7 / 2.5	196.3	(c)	2012	Y / MP5		N/A	YES	YES
12	27	1239	894.16	0.406	701	52000	DSAW	COAL TAR ENAMEL	1957	1.3 / 5.6	50.4	(a)(3)	2012	Y / Y		N/A	YES	N/A
13	28	1135	894.16	0.406	701	52000	DSAW	COAL TAR ENAMEL	1956	0.0 / 21.2	36.1	(a)(3)	2012	Y / Y	SCC[1]	NO	YES	N/A
14	29	MP5	894.16	0.406	701	52000	DSAW	COAL TAR ENAMEL	1957	5.4 / 4.0	78.5	(c)	2012	Y / MP5	Leak (2/14/2005)	NO	YES	YES
15	30	1219	836.16	0.335	602	52000	DSAW	COAL TAR ENAMEL	1966	10.4 / 5.6	50.4	(a)(1)	2012	Y / Y		N/A	YES	N/A
16	31	1254	845.6	0.302	722	70000	DSAW	FUSION BONDED EPOXY	1992	0.2 / 17.5	36.1	(a)(1)	2012	Y / Y		N/A	YES	N/A
17	169	1233	845.52	0.271	481	52000	DSAW	COAL TAR ENAMEL	1950	1.0 / 3.9	81.7	(a)(1)	2012	Y / Y	Leak (6/7/2007)	NO	YES	N/A
18	170	1227	845.52	0.271	481	52000	DSAW	COAL TAR ENAMEL	1950	2.8 / 2.1	81.7	(a)(1)	2012	Y / Y	Leak (6/7/2007)	NO	YES	N/A
19	171	1218	1073.28	0.344	481	52000	DSAW	COAL TAR ENAMEL	1966	2.4 / 2.1	81.7	(a)(1)	2012	Y / Y	Leak (4/3/2007) / SCC[1]	NLP / NSLP	YES	N/A
20	172	1158	1032.9	0.469	701	52000	DSAW	COAL TAR ENAMEL	1992	0.1 / 0.0	81.7	(a)(2)	2012	Y / Y	SCC[1]	YES	NO	N/A
21	173	1181	836.16	0.335	599	52000	FW	COAL TAR ENAMEL	1954	4.6 / 4.7	48.8	(a)(3)	2012	Y / Y		N/A	YES	N/A
22	174	1180	836.16	0.335	599	52000	DSAW	COAL TAR ENAMEL	1963	0.0 / 4.7	48.8	(a)(3)	2012	Y / Y		N/A	YES	N/A
23	175	MP5	1168.13	0.312	413	52000	DSAW	FUSION BONDED EPOXY	1953	5.9 / 0.9	28.8	(c)	2012	Y / MP5	Leak (10/11/1983)	NO	YES	YES
24	176	MP5	1168.13	0.312	413	52000	DSAW	FUSION BONDED EPOXY	1953	6.0 / 0.9	28.8	(c)	2012	Y / MP5	Leak (10/11/1983)	NO	YES	YES
25	281	1054	809.28	0.281	510	52000	FW	COAL TAR ENAMEL	1947	13.2 / 2.3	39	(a)(3)	2012	Y / Y	SCC[4]	NSLP	YES	N/A
26	282	1120	808.7	0.324	589	52000	DSAW	COAL TAR ENAMEL	1950	13.2 / 2.6	39	(a)(3)	2012	Y / Y	Leak (9/9/2011) / SCC[4]	NO / NSLP	YES	N/A
27	283	1120	808.7	0.324	589	52000	DSAW	COAL TAR ENAMEL	1950	13.4 / 2.3	39	(a)(3)	2012	Y / Y	Leak (9/9/2011) / SCC[4]	NO / NSLP	YES	N/A
28	284	1221	1073.28	0.344	636	65000	DSAW	FUSION BONDED EPOXY	2003	0.3 / 19.0	39	(a)(2)	2012	Y / Y		N/A	YES	N/A
29	285	1221	1073.28	0.344	636	65000	DSAW	FUSION BONDED EPOXY	2003	0.0 / 19.0	39	(a)(2)	2012	Y / Y		N/A	YES	N/A