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

1200 New Jersey Ave., S.E.
Washington DC 20590

DEC 15 2008

Mr. Don Hawkins
Senior Vice President Operations and Engineering
Transwestern Pipeline Company
711 Louisiana Street, Suite 900
Houston, TX 77002

Docket No. PHMSA-2007-27121

Dear Mr. Hawkins:

On January 15, 2007, you wrote to the Pipeline and Hazardous Materials Safety Administration (PHMSA) on behalf of the Transwestern Pipeline Company (Transwestern) requesting a waiver of compliance from PHMSA's pipeline safety regulations contained in 49 CFR §§ 192.111, 192.201, 192.505, and 192.619 for the Transwestern San Juan Lateral pipeline in Colorado and New Mexico. The regulations specify the design factor for steel pipe, the required capacity of pressure relieving/limiting stations, hydrostatic strength test requirements, and the process operators use to establish the maximum allowable operating pressure (MAOP) of a gas pipeline.

On October 17, 2008, PHMSA published the final rule, Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines, which becomes effective December 22, 2008. The rule covers the requirements for any pipeline to operate at a design factor of up to 0.80 in Class 1 areas. PHMSA is proceeding with issuing the Transwestern Pipeline Company this special permit as a result of the thorough analysis contained in the Special Permit Analysis and Findings document, prepared well in advance of the final rule. Moreover, since the Transwestern pipeline varies from certain provisions of the final rule, this special permit is necessary to cover all requested variances from regulations and required conditions, and is consistent with, or more stringent than, prior grants of special permit for existing pipelines.

PHMSA is granting this special permit (enclosed), which allows Transwestern to raise the MAOP of the San Juan Lateral segment from Bloomfield to Gallup, New Mexico, from 1202 pounds per square inch gauge (psig) to 1336 psig. This special permit has conditions and limitations, and provides some relief from the Federal pipeline safety regulations for the San Juan Lateral while ensuring that pipeline safety is not compromised.

Docket No. PHMSA-2007-27121

My staff would be pleased to discuss this special permit or any other regulatory matter with you. John Gale, Director of Regulations (202-366-0434), may be contacted on regulatory matters and Alan Mayberry, Director of Engineering and Emergency Support (202-366-5124), may be contacted on technical matters specific to this special permit.

Sincerely,

JD Wiese

Jeffrey D. Wiese
Associate Administrator for Pipeline Safety

Enclosure: Special Permit

U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

SPECIAL PERMIT

Docket Number: PHMSA-2007-27121

Requested By: Transwestern Pipeline Company

Date Requested: January 15, 2007 (Amended May 6, 2008)

Code Sections: 49 CFR §§ 192.111, 192.201, 192.505, and 192.619

Grant of Special Permit:

By this order, The Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to the Transwestern Pipeline Company (Transwestern) subject to the conditions and limitations set forth below. This special permit waives compliance from 49 CFR §§ 192.111, 192.201, 192.505 and 192.619 for a segment of the Transwestern San Juan Lateral natural gas transmission pipeline running southwesterly from Bloomfield, NM, to Gallup, NM, and which consists of a 97.1-mile, 30-inch diameter, mainline and two sections of 36-inch diameter looped pipelines totaling approximately 75 miles. When San Juan Lateral is used throughout this document, it means only that segment of the pipeline to which this special permit applies.

The Federal pipeline safety regulations in § 192.111 limit the design factors[1] for steel natural gas transmission pipelines for Class locations 1, 2 and 3 to the values in the following table:

	Class Location	Maximum Design Factor	Class Location	Maximum Design Factor	Class Location	Maximum Design Factor
General	1	0.72	2	0.60	3	0.50
Un-cased road crossings	1	0.60	2	0.50	3	0.50
Fabricated Assembly	1	0.60	2	0.60	3	0.50
Supported on Bridge	1	0.60	2	0.60	3	0.50
Stations	1	0.50	2	0.50	3	0.50

[1] Design factors limit the hoop stress in a pipeline due to the pipeline operating pressure to a percentage of the specified minimum yield strength (SMYS) of the pipe. For example, a design factor of 0.72 would limit the pipeline pressure to a value that results in a hoop stress level of 72% SMYS.

This special permit allows Transwestern to raise the maximum allowable operating pressure (MAOP) of the San Juan Lateral from 1202 pounds per square inch gauge (psig) to 1336 psig. Accordingly, this special permit allows Transwestern to operate the San Juan Lateral in Class locations[2] 1, 2 and 3 using the design factors in the following table:

	Class Location	Maximum Design Factor	Class Location	Maximum Design Factor	Class Location	Maximum Design Factor
General	1	0.80	2	0.67	3	0.56
Un-cased road crossings	1	0.67	2	0.56	3	0.56
Fabricated Assembly	1	0.67	2	0.67	3	0.56
Supported on Bridge	1	0.67	2	0.67	3	0.56
Stations	1	0.56	2	0.56	3	0.56

Because the proposed operating stress level of 80% specified minimum yield strength (SMYS) is higher than the upper limit of the required overpressure protection under the existing Federal pipeline safety regulations [i.e. 10% over MAOP or 75% SMYS], this special permit also allows Transwestern to design, install and operate pressure relief and limiting devices on the applicable segment of the San Juan Lateral with a capacity that would ensure the pressure in Class locations 1, 2 and 3 pipeline segments would not exceed 104% of the MAOP or the pressure that produces a hoop stress of 83.2% SMYS in Class 1 locations, 69.7% SMYS in Class 2 locations or 58.2% SMYS in Class 3 locations in the event an overpressure situation develops.

This special permit also waives the strength test requirements in § 192.505 and the MAOP regulations in § 192.619, which allows Transwestern to raise the MAOP of the applicable segment of the San Juan Lateral from 1202 psig to 1336 psig.

For the purpose of this special permit, the "*special permit area*" means the area consisting of the entire pipeline right-of-way for those sections along the applicable segment of the San Juan Lateral that will operate above 72% SMYS in Class 1 locations, 60% SMYS in Class 2 locations or 50% SMYS in Class 3 locations.

---

[2] There are currently no class 4 locations on the San Juan lateral. This special permit does not apply to any future class 4 locations on the San Juan Lateral.

PHMSA grants this special permit 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-2007-27121 in the Federal Docket Management System (FDMS) located on the Internet at www.Regulations.gov.

Conditions:

PHMSA grants this special permit subject to the following conditions:

1) Steel Properties: The skelp/plate must be micro alloyed, fine grain, fully killed steel with calcium treatment and continuous casting.
2) Manufacturing Standards: New pipe segments or replacement pipe must be manufactured according to American Petroleum Institute Specification 5L, Specification for Line Pipe (API 5L), product specification level 2 (PSL 2), supplementary requirements (SR) for maximum operating pressures and minimum operating temperatures. Pipe carbon equivalents must be at or below 0.25% based on the material chemistry parameter (Pcm) formula or 0.43% based on the C-IIW formula
3) Fracture Control: API 5L, the American Society of Mechanical Engineers B31.8 Standard (ASME B31.8) and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation, crack propagation and to ensure crack arrest during a pipeline failure caused by a fracture. Transwestern must institute an overall fracture control plan addressing the steel pipe properties necessary to resist crack initiation and crack propagation and to arrest a fracture within 8 pipe joints with a 99% occurrence probability or within 5 pipe joints with a 90% occurrence probability. The plan must include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures of a steel pipeline's toughness and resistance to fracture. The fracture control plan, which must be submitted to PHMSA headquarters, must be in accordance with API 5L, Appendix F and must include the following tests:
   a) SR 5A - Fracture Toughness Testing for Shear Area: Test results must indicate at least 85 % minimum average shear area for all X- 70 heats and 80% minimum shear area for all X- 80 heats with a minimum result of 80% shear area for any single test. The test results must also ensure a ductile fracture and arrest;
   b) SR 5B – Fracture Toughness Testing for Absorbed Energy; and
   c) SR 6 – Fracture Toughness Testing by Drop Weight Tear Test: Test results must be at least 80% of the average shear area for all heats with a minimum result of 60% of the

shear area for any single test. The test results must also ensure a ductile fracture and arrest.

The above fracture initiation, propagation and arrest plan must account for the entire range of pipeline operating temperatures, pressures and gas compositions planned for the pipeline diameter, grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions associated with the *special permit area*. Where the use of stress factors, pipe grade, operating temperatures and gas composition make fracture toughness calculations non-conservative, correction factors must be used. If the fracture control plan for the pipe in the *special permit area* does not meet these specifications, Transwestern must submit to PHMSA headquarters an alternative plan providing an acceptable method to resist crack initiation, crack propagation and to arrest ductile fractures in the *special permit area*.

4) Steel Plate Quality Control for All New Pipeline Segments or Pipe Replacements: The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate or rolled pipe ultrasonic testing (UT) inspection program to check for imperfections such as laminations. UT inspection must be conducted on all factory beveled pipe ends. In addition, pipe body UT inspection must be conducted on a minimum of 100% of pipe joints and all ends, with a minimum coverage of 35% of the pipe body for those joints inspected. Any laminations identified by the UT inspection program must be evaluated in accordance with the acceptance criteria defined in ASTM International Standard ASTM A578/A578M "*Standard Specification for Straight-Beam Ultrasonic Examination of Rolled Steel Plates for Special Applications (ASTM A578)*," Level B or API 5L Paragraph 7.8.10. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat (manufacturing run) of each sequence (approximately 4 heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible four or five scale are acceptable.

5) Pipe Seam Quality Control for All New Pipeline Segments or Pipe Replacements: A quality assurance program must be instituted for pipe weld seams. The pipe weld seam

tests must meet the minimum requirements for tensile strength in API 5L for the appropriate pipe grade properties. A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness (Hv10). The hardness tests must include a minimum of 3 readings for each heat affected zone, 3 readings in the weld metal and 2 readings in each section of pipe base metal for a total of 13 readings. The pipe weld seam must be 100% UT inspected after expansion and hydrostatic testing per API 5L.

6) Mill Hydrostatic Test for All New Pipeline Segments or Pipe Replacements: The pipe must be subjected to a mill hydrostatic test to achieve a minimum stress level of 95% SMYS in the pipe for a minimum duration of 10 seconds. The 95% stress level may be achieved using a combination of internal test pressure and the application of end loads imposed by the hydrostatic testing equipment as allowed by API 5L, Appendix K.

7) Pipe Coating for All New Pipeline Segments or Pipe Replacements: The application of a corrosion resistant coating to the steel pipe must be subject to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repair. The pipe for existing pipeline segments, new pipeline segments and/or replacements must be protected against external corrosion by a non-shielding coating.

8) Field Coating for All New Pipeline Segments or Pipe Replacements: A field girth weld joint coating application specification and quality standards to ensure pipe surface cleanliness, application temperature control, adhesion quality, cathodic disbondment, moisture permeation, bending, minimum coating thickness, holiday detection and repair quality must be implemented in field conditions. Field joint coatings must be non-shielding to cathodic protection (CP). Field coating applicators must use valid coating procedures and be trained to use these procedures.

9) Field Coating: The coatings on existing girth weld joints must be non-shielding to CP.

10) Coatings for Trenchless Installation for All New Pipeline Segments or Pipe Replacements: Coatings used for directional bore, slick bore and other trenchless installation methods must resist abrasions and other damages that may occur due to rocks and other obstructions encountered in this installation technique.

11) Bends Quality: Certification records of factory induction bends and/or factory weld bends must be obtained and retained. All bends, flanges and fittings must have carbon equivalents (CE) below 0.42 or a pre-heat procedure must be applied prior to welding for CE above 0.42.

12) Design Factor - Pipelines: Pipe installed under this special permit in Class 1 location may use a design factor of 0.80, in Class 2 locations may use a design factor of 0.67 and in Class 3 locations may use a design factor of 0.56. Road crossings in Class 1 and 2 locations may use a design factor of 0.67 and 0.56, respectively. New road crossings, railroad crossings and fabricated assemblies must be designed using the existing design factors in § 192.111(b) and (c).

13) Fittings: All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels and compressors) must be rated for a pressure rating commensurate with the MAOP and class location of the pipeline. Designed fittings (including tees, elbows and caps) must have the same design factor as the adjacent pipe.

14) Temperature Control: The compressor station discharge temperature must be limited to 120° Fahrenheit. A temperature above this maximum temperature of 120° Fahrenheit may be approved if Transwestern's technical coating operating tests show that the pipe coating will properly withstand the higher operating temperature for long term operations. If the temperature exceeds 120° Fahrenheit, Transwestern must also institute a coating monitoring program in these areas using ongoing Direct Current Voltage Gradient (DCVG) surveys or Alternating Current Voltage Gradient (ACVG) surveys or other testing to demonstrate the integrity of the coating. This program and results must be provided to the Director, PHMSA Southwest Region at least 60 days prior to implementation of the increased temperature or special permit operations.

15) Overpressure Protection Control: Mainline pipeline overpressure protection must be limited to a maximum of 104% MAOP.

16) Welding Procedures for All New Pipeline Segments or Pipe Replacements: For automatic or mechanized welding the 19th Edition of API 1104, "*Welding of Pipelines and Related Facilities*", will be used for welding procedure qualification, welder qualification and weld acceptance criteria. Operator will use the 19th Edition of API 1104 for all other welding processes. The Director, PHMSA Southwest Region must be notified at least 14 days prior to the beginning of any welding procedure qualification activities. Automated or manual

welding procedure documentation must be submitted to the same PHMSA regional office.

17) Depth of Cover: The soil cover must be a minimum depth of 36 inches in all areas. In areas where threats from chisel plowing or other activities are threats to the pipeline, the top of the pipeline must be installed at least one foot below the deepest penetration above the pipeline. If routine patrols or other observed conditions indicate the possible loss of cover over the pipeline, Transwestern will perform a depth of cover study and replace cover as necessary to meet the minimum depth of cover requirements specified herein. If replacing cover is not practical, the Director, PHMSA Southwest Region may agree to an alternate plan to assure safety in these areas.

18) Construction Quality for All New Pipeline Segments or Pipe Replacements: A construction quality assurance plan to ensure quality standards and controls must be maintained throughout the construction phase with respect to: inspection, pipe hauling and stringing, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, alternating current (AC) interference mitigation and CP systems. All girth welds must be non-destructively examined by radiography or alternative means. The NDE examiner must have all required and current certifications.

19) Interference Currents Control: Control of induced AC from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into the design of the pipeline and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to PHMSA's attention by notifying the appropriate regional office. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place within six months after placing the pipeline in service.

20) Test Level for All New Pipeline Segments or Pipe Replacements: The pre-in service hydrostatic test must be to a pressure producing a hoop stress of at least 100% SMYS and 1.25 X MAOP in areas to operate to 80% SMYS, at least 1.50 X MAOP in areas to operate up to 67% SMYS, and at least 1.50 X MAOP in areas to operate up to 56% SMYS.

21) Assessment of Test Failures: Any pipe failure occurring during a pre-in service hydrostatic test or a hydrostatic test of an existing pipeline segment must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this

examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and to the Director, PHMSA Southwest Region.

22) Supervisory Control and Data Acquisition (SCADA) System Capabilities: A SCADA system to provide remote monitoring and control of the pipeline system must be employed.

23) SCADA Procedures: A detailed procedure for establishing and maintaining accurate SCADA set points must be established to ensure the pipeline operates within acceptable design limits at all times.

24) Mainline Valve Control: Mainline valves located on either side of a pipeline segment containing a High Consequence Area (HCA) where personnel response time to the valve exceeds one hour must be remotely controlled via the SCADA system. The SCADA system must be capable of closing these mainline valves and monitoring the valve position, as well as upstream pressure and downstream pressure at the mainline valve. As an alternative, a leak detection system for mainline valve control is acceptable.

25) Pipeline Inspection: The pipeline must be capable of passing in-line inspection (ILI) tools. All headers and other segments covered under this special permit that do not allow the passage of an ILI device must have a corrosion mitigation plan.

26) Gas Quality Monitoring: An acceptable gas quality monitoring and mitigation program must be instituted to not exceed the following limits:

    a) H_2S (1.0 grain per 100 standard cubic feet or 16 parts per million (ppm), maximum);
    b) CO_2 (3% maximum);
    c) H_2O (less than or equal to 7 pounds per million standard cubic feet and no free water); and
    d) Other deleterious constituents that may impact the integrity of the pipeline.

27) The pipeline must have an ongoing pigging and liquids sampling plan to identify, mitigate and remove deleterious constituents, where applicable.

28) If H_2S is above 8 ppm, the gas stream constituents must be reviewed for implementation of a quarterly pigging/inhibitor injection program, including follow up sampling of liquids at receipt points.

29) Gas Quality Control: Separators or filters/separators must be installed at locations where gas is received into the pipeline where the incoming gas stream quality includes potentially deleterious free liquids and/or particulates to minimize the entry of contaminants and to protect the integrity of downstream pipeline segments.

30) Gas Quality Monitoring Equipment: Equipment, including moisture analyzer, chromatograph and semi-annual H_2S sampling (quarterly sampling where H_2S is above 8 ppm), must be installed to permit the operator to manage and limit the introduction of contaminants and free liquids into the pipeline.

31) Interference Current Surveys: Interference surveys must be performed before increasing the pressure above the existing MAOP to ensure compliance with applicable NACE International Standard Practices 0169 and 0177 (NACE SP 0169 and NACE SP 0177) for interference current levels. If interference currents are found, Transwestern will determine if there have been any adverse effects to the pipeline and mitigate the effects as necessary. Transwestern will report the results of any negative finding and the associated mitigative efforts to the Director, PHMSA Southwest Region.

32) Verification of Cathodic Protection: An interrupted close interval survey (CIS) must be performed in concert and integrated with ILI in accordance with 49 CFR Part 192, Subpart O reassessment intervals for all HCA pipeline mileage. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within an HCA. If any annual test station reading fails to meet 49 CFR Part 192, Subpart I requirements, remedial actions must occur within six months. Remedial actions must include a CIS on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control.

33) Initial Close Interval Survey (CIS) - Initial: Transwestern must have been performed a CIS on the pipeline in the *special permit area* within the two years immediately prior to the increase in operating pressure above the existing MAOP or a CIS must be completed within one year after the pressure increase. The CIS results must be integrated with the ILI results to determine whether any further action is needed.

34) Coating Assessment: Transwestern must perform a DCVG survey or an ACVG survey along the entire length of the *special permit area* not later than one year of the grant of this special permit to verify the pipeline coating conditions and to remediate any integrity issues in the *special permit area.* A DCVG or ACVG survey and remediation need not be performed if Transwestern has performed a DCVG or ACVG and remediation on the pipeline along the entire length of the *special permit area* prior to the grant of this special permit. Transwestern must remediate any damaged coating indications found during these assessments that are classified as moderate (i.e. 35% IR and above for DCVG or 50 dBμV

and above for ACVG) or severe based on NACE International Recommended Practice 0502-2002, Pipeline External Corrosion Direct Assessment Methodology, (NACE RP 0502-2002). A minimum of two coating survey assessment classifications must be excavated, classified and/or remediated per each survey crew and compressor station discharge section. If factors beyond Transwestern's control prevent the completion of the DCVG or ACVG survey and remediation within one year, a DCVG or ACVG survey 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 Director, PHMSA Southwest Region not later than one year after the grant of this special permit.

35) Pipeline Markers: Transwestern must employ line-of-sight markings on the pipeline in the *special permit area* except in agricultural areas or large water crossings such as lakes where line-of-sight markers are not practical. The marking of pipelines is also subject to Federal Energy Regulatory Commission orders or environmental permits and local restrictions.

36) Pipeline Patrolling: Pipeline patrolling must be conducted at least monthly (12 times per calendar year), not to exceed 45 days, to inspect for excavation activities, ground movement, wash-outs, leakage or other activities and conditions affecting the safe operation of the pipeline.

37) Monitoring of Ground Movement: An effective monitoring/mitigation plan must be in place to monitor for and mitigate issues of unstable soil and ground movement.

38) Initial ILI: Transwestern must have been performed an initial ILI inspection of the pipeline in the *special permit area* within the four years immediately prior to the increase in operating pressure above the existing MAOP using a high-resolution magnetic flux leakage (MFL) tool and a geometry tool. The results of the initial ILI must be integrated with the initial CIS required per condition 33 above. Transwestern must evaluate and repair all "Repair Immediately" and "Repair within One Year" anomalies in accordance with condition 42 below prior to increasing the pressure above the existing MAOP.

39) Future ILI: A second ILI using a high-resolution MFL must be completed on the pipeline in the *special permit area* within the first reassessment interval required by 49 CFR Part 192, Subpart O, regardless of HCA classification. Future ILI must be performed on a frequency consistent with Subpart O on the pipeline in the *special permit area.*

40) Direct Assessment Plan: Headers, mainline valve bypasses and other sections in the

special permit area that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment (ECDA/ICDA) criteria. The assessment much be performed within one year prior to the increase in operating pressure above the existing MAOP.

41) Damage Prevention Program: The Common Ground Alliance's (CGA) damage prevention best practices applicable to pipelines must be incorporated into Transwestern's damage prevention program.

42) Anomaly Evaluation and Repair: Anomaly evaluations and repairs in the *special permit area*, regardless of HCA status, must be performed based upon the following:

a) Anomaly Response Time: Repair Immediately

- Any anomaly within a *special permit area* operating up to 80% SMYS with a failure pressure ratio (FPR) equal to or less than 1.1 and/or an anomaly depth equal to or greater than 60% wall thickness loss.
- Any anomaly within a *special permit area* operating up to 67% SMYS with an FPR equal to or less than 1.25 and/or an anomaly depth equal to or greater than 60% wall thickness loss.
- Any anomaly within a *special permit area* operating up to 56% SMYS with an FPR equal to or less than 1.4 and/or an anomaly depth equal to or greater than 60% wall thickness loss.

b) Anomaly Response Time: Repair Within One Year

- Any anomaly within a *special permit area* operating at up to 80% SMYS with a FPR equal to or less than 1.25 and/or an anomaly depth equal to or greater than 40% wall thickness loss.
- Any anomaly within a *special permit area* operating at up to 67% SMYS with a FPR equal to or less than 1.5 and/or an anomaly depth equal to or greater than 40% wall thickness loss.
- Any anomaly within a *special permit area* operating at up 56% SMYS with an FPR equal to or less than 1.8 and/or an anomaly depth equal to or greater than 40% wall thickness loss.

c) Anomaly Response Time: Monitored Conditions

- Anomalies not requiring immediate or one year repairs per paragraphs a) and b) above must be reassessed according to 49 CFR Part 192, Subpart O reassessment intervals.
- Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Gas Integrity Management Program (IMP) to determine the maximum re-inspection interval.

d) Anomaly Assessment Methods
- Transwestern must confirm the remaining strength (R-STRENG) effective area method, , R-STRENG - 0.85dL, and ASME B31G assessment methods are valid for the pipe diameter, wall, thickness, grade, operating pressure, operating stress level and operating temperature. Transwestern must use the most conservative method until confirmation of the proper method is made to PHMSA Headquarters.
- Dents in the pipe in the *special permit area* must be evaluated and repaired per 49 CFR § 192.309(b) for the baseline geometry tool run and per 49 CFR § 192.933(d) for future ILI

43) Potential Impact Radius Calculation Updates: If the pipeline operating pressures and gas quality are determined to be outside the parameters of the C-FER Study, a revised study with the updated parameters must be incorporated into the IMP.

44) Reporting - Immediate: Transwestern must notify the Director, PHMSA Southwest Region within 24 hours of any non-reportable leaks occurring in the *special permit area.*

45) Reporting – 30 Day: At least 30 days prior to an increase in operating pressure above the existing MAOP, Transwestern must report on its compliance with the special permit conditions to PHMSA headquarters and to the Director, PHMSA Southwest Region.

a) Special Permit Conditions 1-26, 31, 32, 34, 35, 37, 38, 40-43, 45, and 47-54 must be completed and implemented with documentation available for PHMSA review prior to operating at a pressure above the existing MAOP.

b) Special Permit 1-54 must be included in the operator's written operating and maintenance (O&M) procedures manual concerning permit condition requirements with documentation available for PHMSA review prior to operating at a pressure above the existing MAOP.

46) Annual Reporting: Transwestern must report the following to the Director, PHMSA

Southwest Region annually[3]:

a) The results of any ILI or direct assessment results performed within the *special permit area* during the previous year;

b) Any new integrity threats identified within the *special permit area* during the previous year;

c) The number of new residences, other structures intended for human occupancy and public gathering areas built within the *special permit area*;

d) Any class or HCA changes in the *special permit area* during the previous year;

e) Any reportable incidents associated with the *special permit area* that occurred during the previous year;

f) Any leaks on the pipeline in the *special permit area* that occurred during the previous year;

g) A list of all repairs on the pipeline in the *special permit area* made during the previous year;

h) On-going damage prevention initiatives on the pipeline in the *special permit area* and a discussion of their success or failure;

i) Any changes in procedures used to assess and/or monitor the pipeline operating under this special permit; and

j) Any company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline to which this special permit applies.

47) Threat Identification and Evaluation: Transwestern must develop a threat matrix consistent with § 192.917 to accomplish the following:

a) Identify and compare any increased risks of operating the pipeline at the higher stress levels allowed by this special permit as compared to the conventional operation; and

b) Describe and implement procedures used to mitigate the risk.

48) Public Education: Transwestern must recalculate the potential impact circle as defined in § 192.903 using the new MAOP. At a minimum, Transwestern must then amend its public education program as required by § 192.616 as follows:

a) Include persons occupying property within *special permit area* and within the potential

---

[3] 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 Special Permit dated March 4, 2008, must be received by PHMSA no later than March 31st each year beginning in 2009.

impact circle in the targeted audience; and

b) Include information about the integrity management activities required by this special permit within the message provided to the audience.

49) Right-of-Way Management Plan: Transwestern must develop and implement a right-of-way management plan to protect the San Juan Lateral from damage due to excavation, third party and other activities. In any areas where increased activities or natural forces could lead to increased threats to the pipeline beyond the initial threat conditions, the management plan must include increased inspections. The management plan must also include right-of-way inspection activities to complement the following:

- Depth of Cover (condition 17)
- Pipeline Markers (condition 35)
- Pipeline Patrolling (condition 36)
- Monitoring of Ground Movement (condition 37)
- Damage Prevention Program (condition 41)
- Threat Identification and Evaluation (condition 47)
- Public Education (condition 48)

50) Change in Class Location: Whenever an increase in population density along the San Juan Lateral indicates a change in class location, Transwestern must confirm or revise the MAOP in accordance with §§ 192.609 and 192.611 except as follows:

a) For segments operating at an increased MAOP in accordance with this special permit that meet the pressure test requirements in § 192.611(a)(1), the corresponding hoop stress of the pipe may not exceed 80% SMYS in Class 2 locations or 67% SMYS in Class 3 locations.

b) For segments operating at an increased MAOP in accordance with this special permit that do not meet the pressure test requirements in § 192.611(a)(1), the corresponding hoop stress of the pipe may not exceed 72% SMYS in Class 2 locations or 60% SMYS in Class 3 locations.

51) Change in Class Location - Anomaly Repair: Transwestern must evaluate and repair all anomalies on any pipeline segment changing from a Class location 1 to Class location 2 or from a Class location 2 to Class location 3 in accordance with condition 42 above.

52) Records: Transwestern must maintain those records demonstrating compliance with all conditions of this special permit for the useful life of the pipeline.

53) Qualification of Personnel: For the purpose of this special permit, a *"covered task"* is any task that meets the requirements in § 192.801(b) and any construction task associated with implementing the increased MAOP allowed by this special permit that can affect the integrity of the pipeline segment. This includes, but is not limited to, tasks associated with construction or pipe replacement activities. Personnel performing these covered tasks on the San Juan Lateral must be qualified in accordance with 49 CFR Part 192, Subpart N.

54) Certification: A senior executive officer of Transwestern must certify in writing the following:

   a) That the San Juan Lateral meets the conditions described in this special permit,

   b) That the written manual of O&M procedures for the San Juan Lateral has been updated to include all additional operating and maintenance requirements of this special permit; and

   c) That Transwestern has reviewed and modified its damage prevention program relative to the San Juan Lateral to include any additional elements required by special permit.

   Transwestern must send a copy of the certification with the required senior executive signature and date of signature to the Director, PHMSA Southwest Region at least 30 days prior to operating the San Juan Lateral at a pressure above the existing MAOP.

Limitations:

PHMSA grants this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether Transwestern has complied with the specified conditions of this special permit.
2) Should Transwestern fail to comply with any of the specified conditions of this special permit, PHMSA may revoke this special permit and require Transwestern to comply with the regulatory requirements in 49 CFR § 192.111, § 192.201, § 192.505, and § 192.619.
3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and require Transwestern to comply with the regulatory requirements in 49 CFR § 192.111, § 192.201, § 192.505, and § 192.619.
4) Should PHMSA revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1), PHMSA will notify Transwestern in writing of the proposed action and provide Transwestern an opportunity to show cause why the action should not be taken