



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

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Washington, DC 20590

**DEPARTMENT OF TRANSPORTATION**  
**PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)**  
**SPECIAL PERMIT**

Docket Number: PHMSA-2006-25802  
Pipeline Operator: CenterPoint Energy Gas Transmission Company  
Date Requested: September 5, 2006  
Code Section(s): 49 CFR 192.111 and 192.201

**Grant of Special Permit:**

Based on the findings set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to CenterPoint Energy Gas Transmission Company (CEGT). The federal pipeline safety regulations in 49 CFR 192.111 limit the design factors and operating stress levels for natural gas transmission steel pipelines to 72 percent of the specified minimum yield strength (SMYS) in class 1 locations, 60 percent SMYS in class 2 locations and 50 SMYS percent in class 3 locations. This special permit allows CEGT to design, construct and operate the Carthage to Perryville pipeline using a design factor and operating stress level of up to 80 percent of the steel pipe's specified minimum yield strength (SMYS) in class 1 locations, 67 percent in class 2 locations and 56 percent in class 3 locations. This special permit also allows CEGT to operate at up to 67 percent at class 1 location road crossings and at up to 56 percent at class 2 road crossings. The Carthage to Perryville pipeline currently has no class 3 locations.

Because the proposed operating stress level of 80 percent is higher than the upper limit of the required overpressure protection under existing regulations [i.e. 10 percent over maximum allowable operating pressure (MAOP) or 75 percent SMYS], CEGT proposes increasing the overpressure protection limit to 104 percent of the pipeline MAOP in class 1 locations,

corresponding to 83.2 percent SMYS. The pipeline overpressure criteria in class 2 areas will conform to existing regulations. The pipeline MAOP will be 1,168 psig.

This special permit, which is subject to the conditions set forth below, covers approximately 172 miles of a 42-inch pipeline starting in Carthage, Texas and ending in Perryville, Richland Parish, Louisiana. For the purpose of this special permit, the "special permit area" means the area consisting of the entire pipeline right-of-way for those segments of the pipeline that will operate above 72 percent of SMYS in class 1 locations and 67 percent in class 2 locations.

**Conditions:**

The grant of this special permit is 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:** The 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 0.23 percent based on the material chemistry parameter (Pcm) 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. CEGT must institute an overall fracture control plan addressing steel pipe properties necessary to resist crack initiation and crack propagation and to arrest a fracture within 8 pipe joints with a 99 percent occurrence probability or within 5 pipe joints with a 90 percent 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 percent minimum average shear area for all X-70 heats and 80 percent

minimum shear area for all X- 80 heats with a minimum result of 80 percent 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 percent of the average shear area for all heats with a minimum result of 60 percent 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, CEGT 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: 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 (body and all ends) ultrasonic testing (UT) inspection program per ASTM A578 to check for imperfections such as laminations. 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 a representative heat 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: 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 percent UT inspected after expansion and hydrostatic testing per APL 5L.

- 6) Puncture Resistance: Steel pipe must be puncture resistant to an excavator weighing up to 65 tons. Puncture resistance will be calculated based on industry established calculations such as the Pipeline Research Council International's "*Reliability Based Prevention of Mechanical Damage to Pipelines*" calculation method.
- 7) Mill Hydrostatic Test: The pipe must be subjected to a mill hydrostatic test pressure of 94 percent SMYS or greater for 10 seconds.
- 8) Pipe Coating: 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.
- 9) Field Coating: 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.
- 10) Coatings for Trenchless Installation: 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. Trenchless installations installed without abrasive resistant coating shall be assessed to determine the external coating condition.
- 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) 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 factors as the adjacent pipe class location.
  - 13) Design Factor - Pipelines: Pipe installed under this special permit in Class 1, 2 and 3 locations may use design factors of 0.80, 0.67 and 0.56 respectively. Road crossings in class 1 and 2 areas may use design factors of 0.67 and 0.56 respectively.
  - 14) Design Factor – Stations: Compressor and meter stations must follow 49 CFR 192.111.
  - 15) 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 CEGT technical coating operating tests show that the pipe coating will properly with-stand the higher operating temperature for long term operations.
  - 16) Overpressure Protection Control: Mainline pipeline overpressure protection must be limited to a maximum of 104 percent MAOP.
  - 17) Welding Procedures: The appropriate PHMSA regional office must be notified within 14 days of the beginning of welding procedure qualification activities. Automated or manual welding procedure documentation must be submitted to the same PHMSA regional office.
  - 18) 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 indicate or other observed conditions indicate the possible loss of cover over the pipeline, CEGT will perform a depth of cover study and replace cover as necessary to meet the minimum depth of cover requirements specified herein.
  - 19) Construction Quality: 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 (NDE) by radiography or alternative means. The NDE examiner must have all required and current certifications.
- 20) 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. 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.
  - 21) Test Level: The pre-in service hydrostatic test must be to a pressure producing a hoop stress of: 100 percent SMYS and 1.25 X MAOP in areas to operate to 80 percent SMYS; at least 1.5 X MAOP in areas to operate to 67% SMYS; and at least 1.5 X MAOP in areas to operate to 56% SMYS.
  - 22) Assessment of Test Failures: Any pipe failure occurring during the pre-in service hydrostatic test 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 the appropriate PHMSA regional office.
  - 23) Supervisory Control and Data Acquisition (SCADA) System Capabilities: A SCADA system to provide remote monitoring and control of the entire pipeline system must be employed.
  - 24) 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.
  - 25) 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 by the SCADA system. The SCADA system must be capable of opening and closing the valve and monitoring the valve position, upstream pressure and downstream pressure. As an alternative, a leak detection system for mainline valve control is acceptable.

- 26) Pipeline Inspection: The pipeline must be capable of passing 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.
- 27) Gas Quality Monitoring: An acceptable gas quality monitoring and mitigation program must be instituted to not exceed the following limits:
  - a) H<sub>2</sub>S (0.5 grains per 100 standard cubic feet or 8 parts per million, maximum);
  - b) CO<sub>2</sub> (3 percent maximum);
  - c) H<sub>2</sub>O (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 must be instituted.
  - e) The pipeline must have an ongoing pigging and liquids sampling plan to identify, mitigate and remove deleterious constituents.
- 29) Gas Quality Control: Filters/separators must be installed at locations where gas is received into the pipeline where the incoming gas stream quality includes potentially deleterious constituents 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 periodic H<sub>2</sub>S sampling, must be installed to permit the operator to manage and limit the introduction of contaminants and free liquids into the pipeline.
- 31) Cathodic Protection: The initial CP system must be operational within 12 months of placing any pipeline segment in service.
- 32) Interference Current Surveys: Interference surveys must be performed within six months of placing the pipeline in service to ensure compliance with applicable NACE International Standard Recommended Practices 0169 and 0177 (NACE RP 0169 and NACE RP 0177) for interference current levels. If interference currents are found, CEGT will determine if there have been any adverse affects to the pipeline and mitigate the affects as necessary. CEGT will report to PHMSA the results of any negative finding and the associated mitigative efforts to the appropriate PHMSA regional office.
- 33) Corrosion Surveys: Corrosion surveys of the affected pipeline must be completed within six months of placing the respective CP system(s) in operation to ensure adequate

external corrosion protection per NACE RP 0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP 0177.

- 34) **Verification of Cathodic Protection:** An interrupted close interval survey (CIS) must be performed in concert and integrated with ILI in accordance with 49 CFR 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 192 Subpart I requirements, remedial actions must occur within six months. Remedial actions must include a close interval survey (CIS) on each side of the affected test station to the next test station and all modifications to the CP system necessary to ensure adequate external corrosion control.
- 35) **Initial Close Interval Survey (CIS) - Initial:** A CIS must be performed on the pipeline within two years of the pipeline in- service date. The CIS results must be integrated with the baseline ILI to determine whether further action is needed.
- 36) **Pipeline Markers:** CEGT 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.
- 37) **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.
- 38) **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.
- 39) **Initial ILI:** CEGT must perform a baseline ILI in association with the construction of the pipeline using a high-resolution Magnetic Flux Leakage (MFL) tool to be completed within three years of placing a pipeline segment in service. CEGT must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of

the pipeline, (just prior to placing the pipeline in service) but no later than six months after placing the pipeline in service under a special permit.

- 40) Future ILI: A second high-resolution MFL inspection must be performed and completed on the pipe subject to this waiver within the first reassessment interval required by 49 CFR Subpart O, regardless of HCA classification. Future ILI must be performed on a frequency consistent with Subpart O for the entire pipeline covered by this waiver.
- 41) Direct Assessment Plan: Headers, mainline valve bypasses and other sections covered by this special permit 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 criteria (ECDA/ICDA).
- 42) Damage Prevention Program: The Common Ground Alliance (CGA) Alliance's damage prevention best practices applicable to pipelines must be incorporated into the CEGT damage prevention program.
- 43) Anomaly Evaluation and Repair: Anomaly evaluations and repairs in the special permit area must be performed based upon the following:
  - a) Anomaly Response Time: Repair Immediately
    - Any anomaly within a waiver area operating up to 80% SMYS with a failure pressure ratio (FPR) equal to or less than 1.1
    - Any anomaly within a waiver area operating up to 67% SMYS with a FPR equal to or less than 1.25
    - Any anomaly within a waiver area operating up to 56% SMYS with a FPR equal to or less than 1.4
  - b) Anomaly Response Time: Repair Within One Year
    - Any anomaly within a waiver area operating at up to 80% SMYS with a FPR equal to or less than 1.25
    - Any anomaly within a waiver area operating at up to 67% SMYS with a FPR equal to or less than 1.5
    - Any anomaly within a waiver area operating at up 56% SMYS with a FPR equal to or less than 1.8
  - c) Anomaly Response Time: Monitored Conditions

- Anomalies not requiring immediate or one year repairs must be reassessed according to CFR 49, Part 192, Subpart O and the American Society of Mechanical Engineers (ASME) standard B31.8S requirements and class location factor.
  - 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
- CEGT 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. CEGT must also use the most conservative method until confirmation of the proper method is made to PHMSA headquarters.
  - Dents in the pipe in the waiver area must be evaluated and repaired per 49 CFR 192.309(b) for initial ILI and per 49 CFR 192.933(d) for future ILI.
- 44) 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.
- 45) Reporting - Immediate: CEGT must notify the appropriate PHMSA regional office within 24 hours of any non-reportable leaks occurring in the special permit area.
- 46) Reporting – 180 Day: Within 180 days of the pipeline in- service date under a special permit, a CEGT senior executive must confirm in a report on its compliance with special permit conditions to PHMSA headquarters and the appropriate regional office.
- 47) Annual Reporting: Following approval of the special permit, a CEGT senior executive must annually report the following:
- a) The results of any in-line inspection (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) Any encroachment in the special permit area, including the number of new residences or public gathering areas;

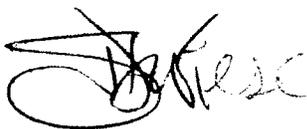
- d) Any class or HCA changes in the special permit area during the previous year;
- e) Any reportable incidents associated with the special permit area that occurred during the previous year;
- f) Any leaks on the pipeline in the special permit area that occurred during the previous year;
- g) A list 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.

**Limitations:**

PHMSA has the sole authority to make all determinations on whether CEGT has complied with the specified conditions. Should CEGT fail to comply with any conditions of this special permit, or should PHMSA determine this special permit is no longer appropriate or that this special permit is inconsistent with pipeline safety, PHMSA may revoke this special permit and require CEGT to comply with the regulatory requirements in 49 CFR 192.111 and 201.

**AUTHORITY:** 49 U.S.C. 60118(c) and 49 CFR 1.53.

Issued in Washington, DC on JUL 31 2007.



Jeffrey D. Wiese,

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