U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

FINAL ENVIRONMENTAL ASSESSMENT
and
FINDING OF NO SIGNIFICANT IMPACT

Special Permit Information:

Docket Number:	PHMSA-2017-0161
Requested By:	Tennessee Gas Pipeline Company, LLC
Operator ID#:	19160
Original Date Requested:	December 7, 2017
Issuance Date:	August 11, 2022
Code Section(s):	49 CFR 192.611(a) and (d), 192.619(a)

I. Background

The National Environmental Policy Act (NEPA), 42 United States Code (USC) 4321 – 4375 et seq., Council on Environmental Quality Regulations, 40 Code of Federal Regulation (CFR) 1500-1508, and U.S. Department of Transportation (DOT) Order No. 5610.1C, requires the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS),[1] to analyze a proposed action to determine whether the action will have a significant impact on the human environment. PHMSA analyzes special permit requests for potential risks to public safety and the environment that could result from our decision to grant, grant with additional conditions, or deny the request. As part of this analysis, PHMSA evaluates whether a special permit would impact the likelihood or consequence of a pipeline failure as compared to the operation of the pipeline in full compliance with the Federal pipeline safety regulations. PHMSA's environmental review associated with the special permit application is limited to impacts that would result from granting or denying the special permit. PHMSA

1 Throughout this special permit the usage of "PHMSA" or "PHMSA OPS" means the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety.

developed this assessment to determine what effects, if any, our decision would have on the environment.

Pursuant to 49 USC 60118(c) and 49 CFR 190.341, PHMSA may only grant special permit requests that are not inconsistent with pipeline safety. PHMSA will impose conditions in the special permit if we conclude they are necessary for safety, environmental protection, or are otherwise in the public interest. If PHMSA determines that a special permit would be inconsistent with pipeline safety or is not justified, the application will be denied.

The purpose of this Final Environmental Assessment (FEA) is to comply with NEPA for the Tennessee Gas Pipeline Company, LLC (TGP)[2] special permit to waive compliance from 49 CFR 192.611(a) and (d) and 192.619(a) for three (3) ***special permit segments*** and one (1) ***special permit inspection area*** along the TGP natural gas transmission pipeline system in West Virginia. This FEA assesses the pipeline special permit request, in accordance with 49 CFR 190.341, and is intended to specifically analyze any environmental impact associated with the waiver of certain Federal pipeline safety regulations found in 49 CFR 192.611(a) and (d) and 192.619(a). This permit requires TGP to implement additional conditions on the operations, maintenance, and integrity management (IM) of the approximately 1.050 miles (***special permit segments***) on the 20-inch diameter Line 100-1 Pipeline (Pipeline) and approximately 46.02 miles (***special permit inspection area***) of the TGP natural gas transmission pipeline system located in Kanawha County, West Virginia.

II. Introduction

Pursuant to 49 USC 60118(b) and 49 CFR 190.341, TGP submitted an application for a special permit to PHMSA on December 7, 2017, requesting that PHMSA waive the requirements of 49 CFR 192.611(a) and (d) and 192.619(a) to permit TGP to maintain the maximum allowable operating pressure (MAOP) of three (3) ***special permit segments*** located in Kanawha County, West Virginia, for which the class location has changed from Class 1 to Class 3 due to a population density increase near the pipeline. Without the special permit, 49 CFR 192.611(a) would require TGP to replace the ***special permit segments*** or reduce the pipeline MAOP.

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[2] Tennessee Gas Pipeline Company, LLC is owned by Kinder Morgan, Inc.

PHMSA will grant a special permit to waive certain regulatory requirements where it is consistent with pipeline safety and which is typically contingent on the performance of additional measures beyond minimum Federal pipeline safety regulations, in accordance with 49 CFR 190.341.

III. Regulatory Background

PHMSA regulations at 49 CFR 192.611(a) require that an operator to confirm or revise the MAOP of a pipe segment that is in satisfactory condition when the hoop stress of the segment is no longer commensurate with the class location. Under 49 CFR 192.611(a), an operator may be required to reduce the operating pressure of a pipe segment, or alternatively, may have to replace the pipe in order to maintain the MAOP. Under 49 CFR 192.619(a)(2) the ***special permit segment*** would be required to be pressure tested to 1.5 times MAOP for eight (8) hours. Below are the relevant text of 49 CFR 192.611(a) and (d) and 192.619(a):

49 CFR 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

(a) If the hoop stress corresponding to the established maximum allowable operating pressure of a segment of pipeline is not commensurate with the present class location, and the segment is in satisfactory physical condition, the maximum allowable operating pressure of that segment of pipeline must be confirmed or revised according to one of the following requirements:

(1) If the segment involved has been previously tested in place for a period of not less than 8 hours:

(i) The maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations, 0.667 times the test pressure in Class 3 locations, or 0.555 times the test pressure in Class 4 locations. The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(ii) The alternative maximum allowable operating pressure is 0.8 times the test pressure in Class 2 locations and 0.667 times the test pressure in Class 3 locations. For pipelines operating at alternative maximum allowable pressure per §192.620, the corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(2) The maximum allowable operating pressure of the segment involved must be reduced so that the corresponding hoop stress is not more than that allowed by this part for new segments of pipelines in the existing class location.

3) The segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its maximum allowable operating pressure must then be established according to the following criteria:

(i) The maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations, 0.667 times the test pressure for Class 3 locations, and 0.555 times the test pressure for Class 4 locations.

(ii) The corresponding hoop stress may not exceed 72 percent of the SMYS of the pipe in Class 2 locations, 60 percent of SMYS in Class 3 locations, or 50 percent of SMYS in Class 4 locations.

(iii) For pipeline operating at an alternative maximum allowable operating pressure per §192.620, the alternative maximum allowable operating pressure after the requalification test is 0.8 times the test pressure for Class 2 locations and 0.667 times the test pressure for Class 3 locations. The corresponding hoop stress may not exceed 80 percent of the SMYS of the pipe in Class 2 locations and 67 percent of SMYS in Class 3 locations.

(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 must be completed within 24 months of the change in class location. Pressure reduction under paragraph (a) (1) or (2) of this section within the 24-month period does not preclude establishing a maximum allowable operating pressure under paragraph (a)(3) of this section at a later date.

49 CFR 192.619 What is the maximum allowable operating pressure for steel or plastic pipelines?

(a)(2)(ii) For steel pipe operated at 100 p.s.i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Table 1 to Paragraph (a)(2)(ii)

Class location	Installed before (Nov. 12, 1970)	Factors, [1] segment - Installed after (Nov. 11, 1970) and before July 1, 2020	Installed on or after July 1, 2020	Converted under § 192.14
1	1.1	1.1	1.25	1.25
2	1.25	1.25	1.25	1.25
3	1.4	1.5	1.5	1.5
4	1.4	1.5	1.5	1.5

[1] For offshore pipeline segments installed, uprated or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For pipeline segments installed, uprated or converted after July 31, 1977, that are located on an offshore platform or on a platform in inland navigable waters, including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

- Section 192.619(a) requires Class 3 location pipe to be pressure tested to 1.5 times MAOP.

IV. Purpose and Need

TGP requested a special permit, and PHMSA has reviewed the special permit application for implementing increased IM activities in lieu of replacing pipe within the ***special permit segments*** located on TGP's Line 100-1 Pipeline in Kanawha County, West Virginia, where the class location has changed from a Class 1 to a Class 3 location, and to include contiguous ***special permit segment*** extensions that may experience further development and class change in the future. This special permit consists of three (3) ***special permit segments*** and waives the requirements of 49 CFR Part 192.611(a) and (d) and 192.619(a) with implementation of the special permit conditions. The special permit will allow TGP to maintain the MAOP of three (3) ***special pipe segments*** for which the class location has changed from Class 1 to Class 3 due to population density increase. Without the special permit, 49 CFR 192.611(a) will require TGP to replace the three (3) ***special permit segments*** or reduce pipeline MAOP. **Attachments A1 through** A3 are general maps that includes the pipeline route showing the ***special permit segments*** and ***special permit inspection area***.

PHMSA is granting the special permit, which includes conditions, for the 5,544.83 feet (approximately 1.050 miles) of ***special permit segments*** and the 46.02 miles of ***special permit inspection area***. The special permit also allows continued operation at the existing MAOP in the event of future class changes within the ***special permit inspection area*** (***special permit segment extensions***), if the ***special permit segment extensions*** meet the special permit conditions applicable to ***special permit segments***.

V. Site Description

The ***special permit segments*** consist of 5,544.83 feet (approximately 1.050 miles) of the 20-inch Line 100-1 Pipeline in Kanawha County, West Virginia. The ***special permit inspection area*** extends across approximately 46.02 miles of the pipeline.

VI. Special Permit Segments and Special Permit Inspection Area

This special permit pertains to the specified ***special permit segments*** and corresponding ***special permit inspection area*** defined in this section. This special permit allows TGP to maintain the current MAOP as shown in **Table 1 – Special Permit Segments**.

1) **Special Permit Segments**:

This special permit applies to the ***special permit segments*** in **Table 1 – Special Permit Segments** and are identified using the TGP survey station (Valve – Station) references.

Table 1 – Special Permit Segments

Special Permit Segment Number[3]	Outside Diameter (inches)	Line Name	Length (feet)	Start Survey Station (Valve - Station)	End Survey Station (Valve - Station)	County or Parish, State	Year Installed	Seam Type	MAOP (psig)
451	20	100-1	3,651.14	120-1 – 14932	120-1 – 18584	Kanawha, WV	1984	DSAW	936
452	20	100-1	1,177.32	120-1 – 20565	120-1 – 21742	Kanawha, WV	1984	DSAW	936
453	20	100-1	716.37	120-1 – 23420	120-1 – 24136	Kanawha, WV	1984	DSAW	936

Notes: DSAW is double submerged arc longitudinal weld seam type.

2) **Special Permit Inspection Area**:

The ***special permit inspection area*** is defined as the area that extends 220 yards on each side of the centerline as listed in **Table 2 – Special Permit Inspection Area**.

Table 2 – Special Permit Inspection Area

Special Permit Inspection Area Number	Special Permit Segment(s) Included	Outside Diameter (inches)	Line Name	Start Survey Station (Valve - Station)	End Survey Station (Valve - Station)	Length[4] (miles/feet)
1	451, 452, 453	20	100-1	118-1 – 18.79	121-1 – 27219.53	46.02/ 242,989.49

[3] On February 3, 2022, TGP rescinded requested ***special permit segments 454, 455, 456, 457, 458, 459, 462,*** and ***463***.

[4] If the ***special permit inspection area*** footage does not extend from launcher to receiver, then the ***special permit inspection area*** must be extended.

PHMSA grants this special permit request based on this document and the "Special Permit Analysis and Findings" document, which is incorporated by reference into this document and can be read in its entirety in Docket No. PHMSA-2017-0161 in the Federal Docket Management System (FDMS) located on the internet at www.regulations.gov.

VII. Alternatives

1) Alternative 1: "No Action" Alternative

Denial of the special permit would require the replacement and pressure testing of all the pipeline segments associated with this special permit request, which includes approximately 1.050 miles of mainline pipe. If TGP opted not to replace the ***special permit segments*** of pipeline, 49 CFR 192.611 requires a reduction in the pipeline MAOP.[5]

2) Alternative 2: "Granted" Action

PHMSA is granting the special permit with conditions, and TGP is allowed to continue to operate at the current MAOP of 936 pounds per square inch gauge (psig) in the Class 3 location without replacing pipe while complying with the special permit conditions, as described below.

All of the special permit conditions are attributes of a robust IM program. These special permit conditions include conducting periodic: Close interval surveys, cathodic protection (CP) reliability improvements, stress corrosion cracking assessment, running inline inspection (ILI) assessments (smart pigs), interference current control surveys, remediating ILI findings through anomaly evaluation and repairs, pipe seam evaluations, pipe properties records review and documentation, and maintaining line-of-sight markers. Many of these integrity activities are currently required in 49 CFR Part 192, Subpart O, an IM Program to manage HCAs at specified reassessment intervals. The assessment and reassessment intervals, the level of remediation and the maintenance activities required in a special permit are more stringent to maintain pipe integrity and protect both the public and the environment for the class location units in which the ***special permit segments*** are located.

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[5] These regulatory options are specified in 49 CFR 192.611 Change in class location: Confirmation or revision of maximum allowable operating pressure.

Overview of Special Permit Conditions:

To provide an equivalent level of safety in the absence of either lowering the pipeline operating pressure or upgrading the pipe, this special permit has additional operations and maintenance requirements (conditions) which are intended to decrease the likelihood of a release of gas. PHMSA believes that these additional measures designed to prevent leaks and ruptures will ensure that the special permit is consistent with pipeline safety. This section provides an overview of the special permit conditions. For TGP specific technical requirements and the special permit conditions can be read in its entirety in the FDMS at Docket No. PHMSA-2017-0161 located on the internet at www.regulations.gov or on the PHMSA website for special permits issued at https://www.phmsa.dot.gov/pipeline/special-permits-state-waivers/special-permits-issued.

1) **Current Status of Pipe in the Ground**

   To ensure that key characteristics of the pipe currently installed in each ***special permit segment*** is known, records that confirm pipe specifications, successful pressure tests, and girth weld non-destructive tests are required. Should records be unavailable or unacceptable, additional activities as detailed in the special permit must be completed. If these additional activities are not completed or should pipe be discovered that does not meet specific requirements of eligibility, the ***special permit segment*** must be replaced.

2) **Operating Conditions**

   The ***special permit inspection area*** must continue to be operated at or below the existing MAOP until a restoration or uprating plan has been approved, if allowed by the special permit. To ensure compliance with special permit conditions, TGP's Operations and Maintenance Manual (O&M), IM Program, and Damage Prevention (DP) program must be modified to implement the special permit conditions. In addition, PHMSA must approve any long-term flow reversals that would impact the ***special permit segments***.

3) **Threat Management**

   Threats are factors that can lead to the failure of a pipeline. Activities are required to identify, assess, remediate, and monitor threats to the pipeline.

   a) **General activities.** TGP must perform annual data integration and identification of threats to which the ***special permit inspection area*** is susceptible. These activities must include integrity assessments with specific inline inspection tools, strict anomaly repair criteria, and appropriate environmental assessment and permitting. Additional integrity assessment methodologies may be used if allowed by the special permit. Integrity assessments must then be conducted periodically at an interval determined in the special permit for each threat identified.

b) **External corrosion control requirements.** The special permit requires additional activities to monitor and mitigate external corrosion. These activities include installation and annual monitoring of CP test stations, periodic close interval surveys (CIS), and clearing or remediating shorted casings that may impede CP effectiveness. These activities ensure the appropriate level of CP is reaching the pipeline in areas where coating loss or damage has occurred in order to prevent or mitigate external corrosion. In addition, TGP will be required to develop and implement a plan that identifies and remediates interference from alternating or direct current (AC/DC) sources (such as high-voltage powerlines) that could adversely impact the effectiveness of CP.

c) **Internal corrosion control requirements.** The special permit includes gas quality specifications to mitigate internal corrosion because internal corrosion is highly dependent on the quality of the gas transported within the pipeline and.

d) **Stress corrosion cracking (SCC) requirements.** To ensure that SCC is discovered and remediated, any time a pipe segment in the ***special permit inspection area*** is exposed during an excavation, TGP must examine coating to determine type and condition. If the coating is in poor condition, TGP must conduct additional SCC analysis. If SCC is confirmed, TGP must implement additional special permit defined remediation and mitigation.

e) **Pipe seam requirements.** TGP must perform an engineering integrity analysis to determine susceptibility to seam threats. TGP must re-pressure test a ***special permit segment*** with an identified seam to ensure the issue is not systemic in nature.

f) **External pipe stress requirements.** Upon identification of any source of external stress on the pipeline (such as soil movement), TGP must develop procedures to evaluate and periodically monitor these stresses.

g) **Third-party specific requirements.** To assist in identifying the pipeline location and minimizing the chance of accidental pipeline strikes, TGP must install and maintain line-of-site markers for the pipeline. TGP must perform mitigation activities for any location where a depth-of-cover survey shows insufficient soil cover.

4) **Consequence Mitigation**

To ensure quick response and decreased adverse outcome in the event of a failure, each side (upstream and downstream) of each ***special permit segment*** must have and maintain operable automatic shutdown valves (ASV) or remote-controlled valves (RCV). TGP must monitor valves through a control room with a supervisory control and data acquisition (SCADA) system. In addition to the mainline valves, should a crossover or lateral connect between the valve locations, additional isolation valves may be required. To ensure a leak is discovered promptly, leakage surveys are required twice a year.

5) **Gas Leakage Surveys and Remediation**

The ***special permit segment*** and ***special permit inspection area*** have requirements in the special permit to conduct leakage surveys more frequently than is presently required in 49 CFR 192.706. Gas leakage surveys using instrumented gas leakage detection equipment must be conducted along each ***special permit segment*** and at all valves, flanges, pipeline tie-ins with valves and flanges, ILI launcher, and ILI receiver facilities in each ***special permit inspection area*** at least twice each calendar year, not to exceed 7½ months. The type of leak detection equipment used, survey findings, and remediation of all instrumented gas leakage surveys must be documented by operator. The special permit will require a three-step grading process with a time interval for remediation based upon the type of leak.

6) **Post Leak or Failure**

Should an in-service leak occur, the leak must be graded and remediated as required in the permit. In addition, for all in-service or pressure test leak/failure(s), TGP must conduct a root cause analysis to determine the cause. If the cause is determined to be systemic in nature, TGP must implement a remediation plan or the ***special permit segment*** must be replaced, as determined by the special permit specific conditions.

7) **Class Location Study and Potential Extension of Special Permit Segment**

TGP must conduct a class location study at an interval specified in the special permit. This allows TGP to quickly identify extended locations that must comply with the ***special permit*** requirements. TGP may extend a ***special permit segment*** with proper notification, update of the Final Environmental Assessment, and implementation of all requirements in the special permit.

8) **PHMSA Oversite and Management**

PHMSA maintains oversight and management of each special permit. This includes annual meetings with executive level officers on special permit implementation status, written certification of the special permit, special permit required notification of planned activities, notification of root cause analysis results, and notification prior to certain excavation activities so that PHMSA may observe.

9) **Documentation**

TGP must maintain documentation that supports compliance with special permit conditions for the life of the pipeline.

VIII. Affected Resources and Environmental Consequences

A. Affected Resources and Environmental Consequences of the Granted Action and the "No Action" Alternative

TGP is granted a special permit that waives compliance with 49 CFR 192.611(a) and (d) and 192.619(a) for three (3) ***special permit segments*** totaling 5,544.83 feet (approximately 1.050 miles) located within one (1) ***special permit inspection area*** totaling approximately 46.02 miles. TGP must comply with the special permit conditions within the ***special permit segments***.

Potential risks from the regulatory waiver to pipeline integrity will be analyzed for each ***special permit segment*** to evaluate the potential for impacts or increased risk to safety or environmental resources.

1) **Affected Resources and Environmental Consequences of the Selected Action**

Will a special permit benefit the public? If so, please explain how.

Allowing TGP to avoid pipeline replacement while requiring compliance with special permit conditions including IM has fewer environmental impacts, including decreased Greenhouse Gas (GHG) emissions. To replace a pipeline, TGP would need to blowdown the entirety of a segment of pipe between two (2) isolating valves (approximately 10 to 15 miles) in order to replace any small portion of pipe (i.e., 200 feet) in that segment. In a blowdown, the operator releases to atmosphere the entire contents (pure natural gas) of the pipeline. These blowdown emissions vary depending upon the diameter of the pipeline and operating pressure. Further, grant of the special permit will allow TGP to avoid impact to right of way vegetation, soils, and possibly waterways due to approximately 1.050 miles of excavation to replace pipe. TGP will avoid disturbing the right of way of property owners except for the additional inspections that may be required to satisfy the conditions of the special permit such as those related to the IM Program for HCAs, additional SCC verification digs, and potential anomaly evaluations/repairs.

Safety:

a) Describe potential safety risks that could be associated with waiving the cited regulations. How could those risks be relevant to the operation and operation history of this pipeline? How will the protections normally provided by the regulation be provided under the special permit, if granted?

Class locations are based upon the population (dwellings for human occupancy) within a "class location unit" which is defined as an onshore area that extends 220 yards on either side of the centerline of any continuous 1-mile of pipeline. These locations are determined by surveying the pipeline for population growth. The more conservative safety factors are required as dwellings for human occupancy (population growth) increases near the pipeline. Replacing existing pipe in areas that have experienced population growth with stronger pipe with new coating would provide significant safety protections. However, under the conditions of the special permit, TGP will be required to comply with the special permit conditions in the ***special permit segments*** and the ***special permit inspection area***.

This FEA incorporates the SPAF, which is available under this docket on regulations.gov. The SPAF does not describe any integrity issue that would affect the approval of the special permit or the development of the special permit conditions.

The special permit conditions are designed to prevent, identify, and repair integrity issues in the ***special permit segments*** and the ***special permit inspection area***. The effect of the monitoring and maintenance requirements in the special permit conditions will protect the integrity of the pipe and the population living near the pipeline segment to a similar degree of a lower MAOP, new pressure test, or a thicker walled or higher-grade pipe without the special permit IM protections.

The safety risk with respect to this request for a special permit focuses on maintaining the integrity of the pipeline and to the increased population. Granting this special permit does not increase the potential impact radius (PIR) the radius of a circle within which the potential failure of the pipeline could have significant impact on people or property) of the pipeline. However, the risk from the increased human population around the pipeline will be mitigated through implementation of the special permit conditions.

PHMSA will require IM inspections for pipeline segments adjacent to the ***special permit segments***, which will lower the risk in areas beyond the special permit. PHMSA will require that TGP conduct IM Procedures (conditions in the special permit) on the ***special permit inspection area*** as defined in the special permit. TGP must implement the conditions in ***special permit inspection area*** for the duration of the special permit.

Full implementation of the conditions in the special permit provides an equivalent or greater level of safety for the public and environment. The ***special permit segments*** will be treated as HCAs with the additional risk analysis and remedial activities associated with this designation. The special permit also includes several conditions that address potential safety threats and risks. Among these are incorporation of these ***special permit segments*** into the Kinder Morgan IMP, additional close interval corrosion surveys, implementation of a CP reliability improvement plan, a more comprehensive SCC assessment program, an ILI program with intervals not to exceed seven (7) years, anomaly evaluation and repair meeting more stringent criteria, additional testing and remediation of interference currents caused by induced alternating current sources, pipe seam evaluations, criteria for the identification of pipe properties, installation of line-of-sight markers, and the integration of all inspection and remediation data. This comprehensive list of additional risk related special permit conditions incorporated in the special permit is intended to provide for a significant added level of safety for the ***special pipeline segments*** and ***special permit inspection area***.

b) Will operation under a special permit change the risk of rupture or failure?

Operation under the special permit is expected to reduce the risk of failure due to the addition of extensive special permit conditions requiring additional maintenance, monitoring, inspection, and repair conditions. The ***special permit segments*** must be inspected at intervals similar to IM

Program intervals, which will maintain the integrity of the pipe segments over the life of the special permit.

c) If a failure occurred, will consequences and spill or release volumes be different if PHMSA granted the permit?

If PHMSA were to deny the special permit application and TGP opted to reduce pressure instead of replacing the ***special permit segments*** with stronger pipe, the release volumes and consequences could be less than if PHMSA granted the special permit request or if PHMSA denied the special permit request and TGP opted to replace the pipe. However, PHMSA has no authority over which compliance option TGP selects in the event that PHMSA denies the request. If PHMSA grants the special permit, the consequences of any spill or release will not be impacted in comparison as a result of the special permit and the potential for such an event is expected to be less likely with the added safety programs noted above.

d) For Part 192 special permit request, will the Potential Impact Radius (PIR) of a rupture change under the special permit? Please calculate and provide the PIR data, if applicable. Will more people be affected by a failure if PHMSA granted the permit?

If PHMSA were to deny the special permit application and TGP opted to reduce pressure instead of replacing the ***special permit segments*** with stronger pipe, the PIR would be less than if PHMSA granted the special permit request or if PHMSA denied the special permit request and TGP opted to replace the pipe. However, PHMSA has no authority over which compliance option TGP selects in the event that PHMSA denies the request. The PIR as calculated in accordance with 49 CFR 192.903 does not change under the special permit since the MAOP and pipe diameter will not change, thus there is no additional impact on the public.

e) Will operation under the special permit have an effect on pipeline longevity or reliability? Will there be any life cycle or maintenance issues?

Operation under the special permit conditions that provide an additional level of safety is expected to have a positive impact on pipeline longevity and reliability. PHMSA does not anticipate any deleterious life cycle or maintenance issues related to operation of the pipeline with the special permit.

<u>Environmental Impacts</u>:

a) Explain how operation under the special permit will impact the environment as compared to the status quo in the absence of a special permit, either positively, negatively, or not at all.

Increased maintenance, monitoring and repair standards required by the special permit conditions could lead to increased yet sporadic and temporary vehicle presence, excavation activity, emissions, and noise along the ***special permit segments*** and the ***special permit inspection area*** throughout the duration of the special permit. Unless mitigated, exposed soil resulting from excavation can cause increased airborne dust, erosion, and siltation of nearby waterways. In any single location, the impacts will likely be minimal and temporary. The special permit conditions are designed and intended to decrease the likelihood of a pipeline anomaly forming or increasing to a severity that could result in pipeline failure.

Approval of the special permit will have a positive environmental impact for the ***special permit segments*** that were subject to class location change that do not require pressure testing or pipeline replacement due to the avoidance of impacts. TGP will avoid disturbing the right of way of property owners except for the additional inspections that may be required to satisfy the conditions of the special permit such those related to the IM Program for HCAs, additional verification digs, and potential anomaly evaluations/repairs.

For each individual maintenance activity, TGP will evaluate the potential environmental consequences and affected resources of land disturbances and water body crossings caused by construction activities (including adding, modifying, replacing, or removing any facility) for the related environmental permits associated with any TGP activity. This evaluation is outlined in Kinder Morgan's O&M Procedure 1205: Land Disturbance, Construction, and Environmental Permits, and referenced forms and procedures. This procedure requires obtaining the required permits prior to conducting any construction activity. These procedures ensure that all activities resulting in land disturbances or construction of new or modified facilities comply with the requirement to obtain all applicable environmental permits and other applicable environmental authorizations. These procedures contain information required to identify activities subject to Federal, state, and local environmental authorizations related to the work and to obtain those authorizations. The procedures require a review by TGP Environmental Services staff prior to the start of work, incorporation of environmental requirements into the project implementation, and ensuring outstanding (environmental) requirements are incorporated into facility operation.

If the activities do not qualify under the requirements of Sections 2.55(a) or 2.55(b) facilities or the blanket certificate, TGP will pursue authorization in accordance with Section 7 of the Natural Gas Act.[6]

b) Explain whether and how operation under the special permit will impact each of the environmental resources set out in the Site Description portion of this document: land use planning, surface waters (including wetlands), drinking water, soils and vegetation, wildlife habitats (including fisheries), cultural resources, socioeconomics, Native Americans, etc.? Focus on environmental aspects that are impacted. Are there any geologic hazards? Will any of these impacts be significant?

As already noted, this special permit involves pipeline facilities at various locations. Airborne dust emissions, erosion, and siltation to nearby waterbodies can result from exposed soil that exists during excavation activities that may be required to comply with the IM conditions. These impacts will be addressed and mitigated in accordance with the applicable Kinder Morgan procedures and FERC requirements, see **Attachment B**. Approval of the special permit request will avoid disturbance to the environment, public roadways, businesses, and homes since pipe replacement will not be required.

c) Discuss direct, indirect, and cumulative impacts.

The ***special permit segments*** addressed by this special permit has been buried and undisturbed for many years. The current pipeline cover has therefore returned to its original state in most cases. Impacts resulting from pressure testing or pipe replacement would be temporary in nature and the pipeline right of way would be restored in accordance with required environmental regulations. Direct, indirect, or cumulative impacts associated with activities related to the special permit or denial of the special permit will not be significant.

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[6] See **Attachment B**.

d) Briefly summarize environmental aspects that will not be impacted. Explain why these resources won't be impacted.

If the ***special permit segment*** does not require pressure testing or pipe replacements, it will be operated in nearly the same manner as it is currently operated. The special permit will allow approximately 1.050 miles of pipeline to remain in its current state and not require excavation or disruption of landowner activities. Unless localized excavations are needed, right of way activities (such as additional pipeline markers) may increase in frequency due to the special permit conditions, but it is anticipated that there will be a very minimal added environmental impact related to those activities, and the intention of these maintenance activities is to avoid pipeline leaks or failures. All ILI Tool inspections to determine any pipeline integrity issues due to corrosion or third-party damage will be propelled down the pipeline by gas flow volumes pushing ILI tools through the pipeline segment. Other IM inspections will be performed along the ***special permit segments'*** right of way.

e) Explain whether and how each of these safety measures addresses the safety risks and environmental impacts, if any, of granting the permit.

Each of the special permit conditions have been included and designed to address the anticipated safety risks and environmental impacts of the TGP ***special permit segments*** covered by the special permit.

f) Explain whether there will be any safety risks or environmental impacts beyond those that will exist in the absence of a special permit.

If the special permit were denied, TGP would need to replace the ***special permit segments*** that have experienced population growth sufficient to result in class change with stronger pipe coated with superior coating. However, there are no known safety threats or risks or environmental impacts that are not addressed by the special permit conditions. The ***special permit segments*** included in the special permit are currently operating safely and are expected to continue to perform in that same manner.

g) Will implementation of the safety measures themselves have any environmental impacts? If so, will they be significant? Discuss direct, indirect, and cumulative impacts.

The additional safety measures provided by the special permit conditions will result in minor environmental impacts from soil disturbance and the existence of personnel, vehicle, and equipment on site. These activities could cause temporary increases noise, dust, vehicle emissions, and siltation runoff. The impacts will not be significant and will be lesser in degree to impacts related to pressure tests and/or pipe replacements. Please see the Site Description section, which outlines the environmental review process followed by TGP prior to any excavation being implemented. TGP follows a procedural process as dictated by Federal, State, and local entities to assure compliance with all environmental regulations and requirements as outlined in this prior section.

PHMSA has reviewed the 49 CFR Part 192 requirements for replacing the pipeline and the conditions of the special permit including integrity management practices and considers both to have similar environmental and right-of-way impacts. These impacts will be mitigated by following the FERC procedures outlined in **Attachment B**.

TGP will submit an annual report to the FERC pursuant to Section 2.55(b) concerning replacement activities performed in the prior calendar year that were exempt from the advance notification requirements as specified in Section 2.55(b)(2), see **Attachment B**. The following items are provided to FERC:

(i) A brief description of the pipeline facilities to be replaced (including pipeline size and length, compression horsepower, design capacity, and cost of construction);
(ii) Current U.S. Geological Survey 7.5-minute series topographic maps showing the location of the facilities to be replaced; and
(iii) A description of the procedures to be used for erosion control, revegetation and maintenance, and stream and wetland crossings.

TGP will submit an annual report of Blanket Certificate Activities performed pursuant to Sections 157.208, and 385.2011 of the FERC regulations. The following information will be provided pursuant to the applicable blanket certificate regulation:

- Section 157.208 (Construction, acquisition, operation, replacement, and miscellaneous rearrangement of facilities):
  (1) A description of the facilities installed pursuant to this section, including a description of the length and size of pipelines, compressor horsepower, metering facilities, taps, valves, and any other facilities constructed;

(2) The specific purpose, location, and beginning and completion date of construction of the facilities installed, the date service commenced, and, if applicable, a statement indicating the extent to which the facilities were jointly constructed;

(3) The actual installed cost of each facility item listed pursuant to paragraph (e)(1), separately stating the cost of materials and labor as well as other costs allocable to the facilities;

(4)(i) A description of the contacts made, reports produced, and results of consultations which took place to ensure compliance with the Endangered Species Act, the National Historic Preservation Act and the Coastal Zone Management Act;

(ii) Documentation, including images, that restoration of work areas is progressing appropriately;

(iii) A discussion of problems or unusual construction issues, including those identified by affected landowners, and corrective actions taken or planned; and

(5) For acquisitions of facilities:

(i) A statement referencing the date of issuance, docket number and title of the proceeding for any certificate issued by the Commission authorizing the facilities acquired; and

(ii) The amounts recorded in the accounts of the vendor (seller or lessor) that apply to the facilities acquired and the accumulated provisions for depreciation, depletion, and amortization.

h) Environmental Justice

The special permit alternative associated with this special permit will not have an adverse impact on the population along the pipeline including local, minority, low income, or limited English proficiency populations as shown below in **Table 3 - Demographic Information for Special Permit Segments – Using EPA EJScreen**.

The special permit is intended to maintain or increase safety overall with the implementation of safety conditions in the ***special permit segments***. Many special permit conditions also apply to the ***special permit inspection area*** and will not have a disparate impact on any minority, low income, or limited English proficiency populations. This special permit will also reduce climate change impacts, which are understood to disproportionately affect low-income and minority communities. Therefore, consistent with DOT Order 5610.2C ("Department of Transportation

Actions to Address Environmental Justice in Minority Populations and Low-Income Populations") and Executive Orders 12898 ("Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations"), 13985 ("Advancing Racial Equity and Support for Underserved Communities Through the Federal Government"), 13990 ("Protecting Public Health and the Environment and Restoring Science To Tackle the Climate Crisis"), 14008 ("Tackling the Climate Crisis at Home and Abroad"), 12898 and DOT Order 5610.2(a), and Department of Transportation Actions to Address Environmental Justice in Minority Populations and Low-Income Populations, PHMSA does not anticipate that the special permit will result in disproportionately high and adverse effects on minority or low-income populations.

Table 3 – Demographic Information for Special Permit Segments – Using EPA EJScreen

Special Permit Segment	State	County	Total Population (Along Special Permit Segment)	People of Color Population	Low Income Population	Linguistically Isolated
451	WV	Kanawha	35	0%	11%	0%
452	WV	Kanawha	5	4%	53%	2%
453	WV	Kanawha	19	2	50%	0

Minority*: The term minority is used in the currently active DOT Environmental Justice Order 5610.2(a), available at: https://www.fhwa.dot.gov/environment/environmental_justice/ej at dot/orders/order_56102a/index.cfm

People of Color**: The term people of color is used in EPA's Environmental Justice Screening and mapping tool (EJSCREEN). An overview of demographic indicators through EJSCREEN is available at: https://www.epa.gov/ejscreen/overview-demographic-indicators-ejscreen.

i) Climate Change

The issuance of the special permit will result in avoiding the release of unburned methane gas, a potent GHG. If the special permit was denied and TGP had to replace the ***special permit segments*** of pipeline, TGP would have to blowdown the entirety of a segment of pipe between two (2) isolating valves at a reduced pressure in order to replace any small portion of pipe (i.e., 200 feet) in that segment. If the pipeline operator fails to implement mitigation strategies for a blowdown, large quantities of unburned methane, i.e., the entire contents of the pipeline between block valves, is released. While pipeline operators can and should implement mitigation strategies, including pressure reduction followed by removal and storage of remaining methane during repairs, PHMSA does not currently have authority to require these measures.

While emissions from increased monitoring, maintenance, and repair activities in the ***special permit inspection area*** could offset some of the gains of avoiding blowdown, these conditions are designed to reduce the likelihood of a pipeline failure, which could have catastrophic safety and environmental impacts.

2) **Comparative Environmental Impacts of Alternatives**

If the special permit was not granted, TGP must comply with 49 CFR 192.611(a) and (d), and 192.619(a). TGP would be required to replace existing pipe with heavier walled pipe to maintain the current pipeline MAOP.

Denial of the permit and full adherence to the 49 CFR Part 192 would afford the protections described above that are associated with either: A lower MAOP, new pressure test, or heavier walled or higher-grade pipe. Denial of the special permit would mean for most of these ***special permit segments*** that the special permit condition IM requirements would probably not be implemented in non-HCA locations, such as the ***special permit inspection area***.

Denial of the special permit would require excavation to remove existing pipe, acquiring environmental permits where necessary, and pressure testing of the replacement pipeline segments. This action would create an impact to vegetation, soils, and possibly waterways due to the excavation, use of public roadways, and the impacted right of way during construction.

TGP will evaluate the potential environmental consequences and affected resources of land disturbances and water body crossings caused by construction activities (including adding, modifying, replacing, or removing any facility) for the related environmental permits associated with any TGP activity. This evaluation is outlined in Kinder Morgan's O&M Procedure 1205: Land Disturbance, Construction, and Environmental Permits, and referenced forms and procedures, which requires obtaining the required permits prior to conducting any construction activity. These procedures ensure that all activities resulting in land disturbances or construction of new or modified facilities comply with the requirement to obtain all applicable environmental permits and other applicable environmental authorizations. These procedures contain information required to identify activities subject to Federal, State, and local environmental authorizations related to the work and to obtain those authorizations. The procedures require a review by TGP Environmental Services staff prior to the start of work, incorporation of environmental requirements into the project implementation, and ensuring outstanding (environmental) requirements are incorporated into facility operation.

If the activities do not qualify under the requirements of 2.55(a) or 2.55(b) facilities or the blanket certificate, TGP will pursue authorization in accordance with Section 7 of the Natural Gas Act.

IX. Request for Public Comments Placed on Docket PHMSA-2017-0161

PHMSA published the special permit request in the Federal Register (87 FR 19735) for a 30-day public comment period from April 5, 2022, through May 5, 2022. The special permit application from TGP, draft environmental assessment, and draft special permit conditions were available in Docket No. PHMSA-2017-0161 at: www.regulations.gov for public review. PHMSA received no public comments concerning this special permit renewal request through May 5, 2022.

X. Finding of No Significant Impact

In consideration of the DEA and the special permit conditions explained above, PHMSA finds that no significant negative impact will result from the issuance and full implementation of the above-described special permit to waive the requirements of 49 CFR 192.611(a) and (d), and 192.619(a) for the three (3) ***special permit segments***, which consists of 5,544.83 feet (approximately 1.050 miles) of 20-inch diameter Line 100-1 Pipeline located in Kanawha County, West Virginia. This special permit will require TGP to implement additional conditions on the operations, maintenance, and IM of the ***special permit segments*** and ***special permit inspection area***.

The granted special permit conditions are available in the FDMS Docket No. PHMSA-2017-0161 at: www.regulations.gov for public review.

XI. Bibliography

No other agencies were consulted, but PHMSA considered environmental information, special permit conditions, and documents submitted by TGP.

Attachments:

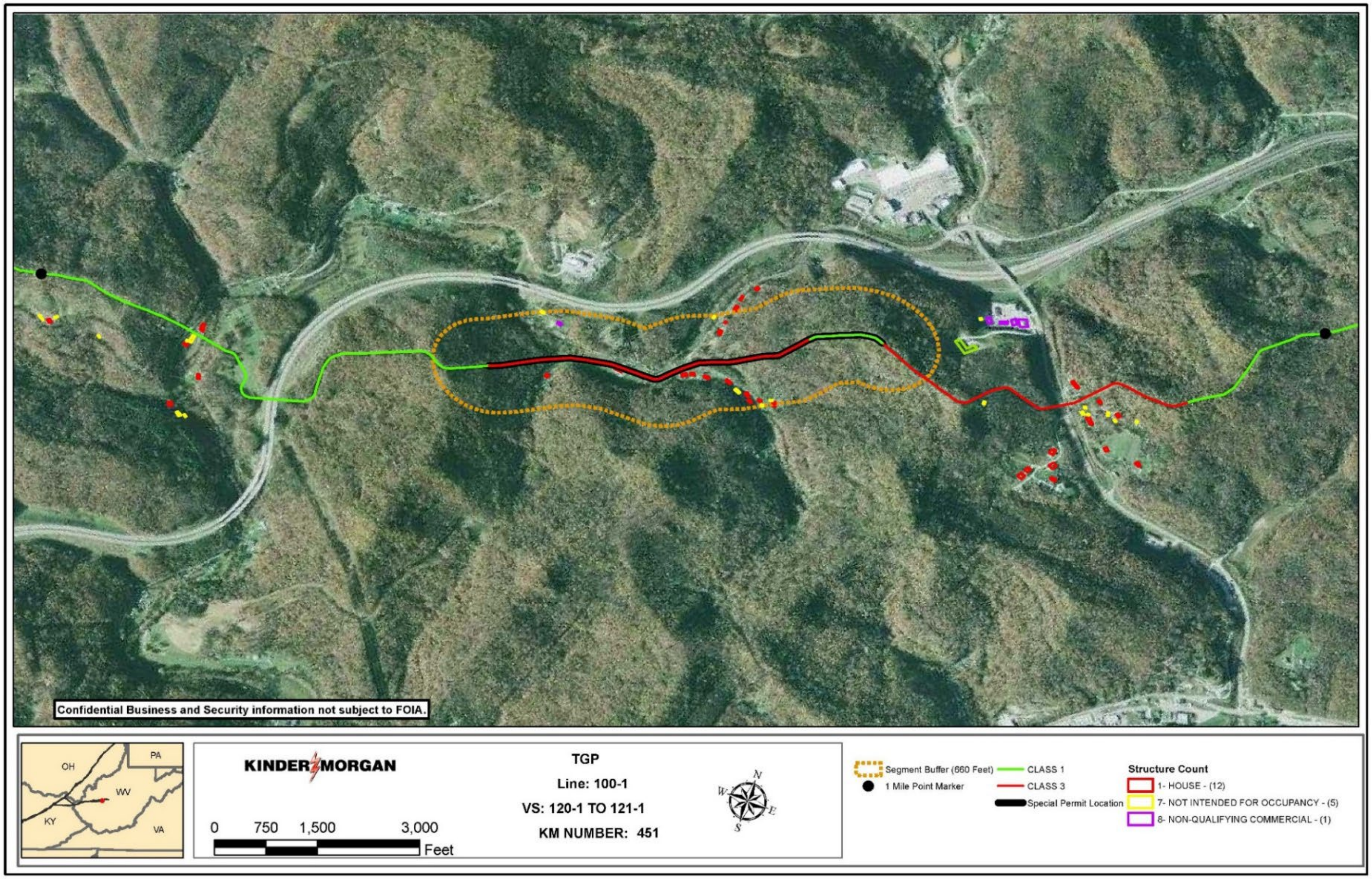
Attachment A – Maps of TGP ***Special Permit Segments*** and ***Special Permit Inspection Area***

Attachment B – Guidance of Repairs to Interstate Natural Gas Pipelines Pursuant to FERC Regulations (July 2005)

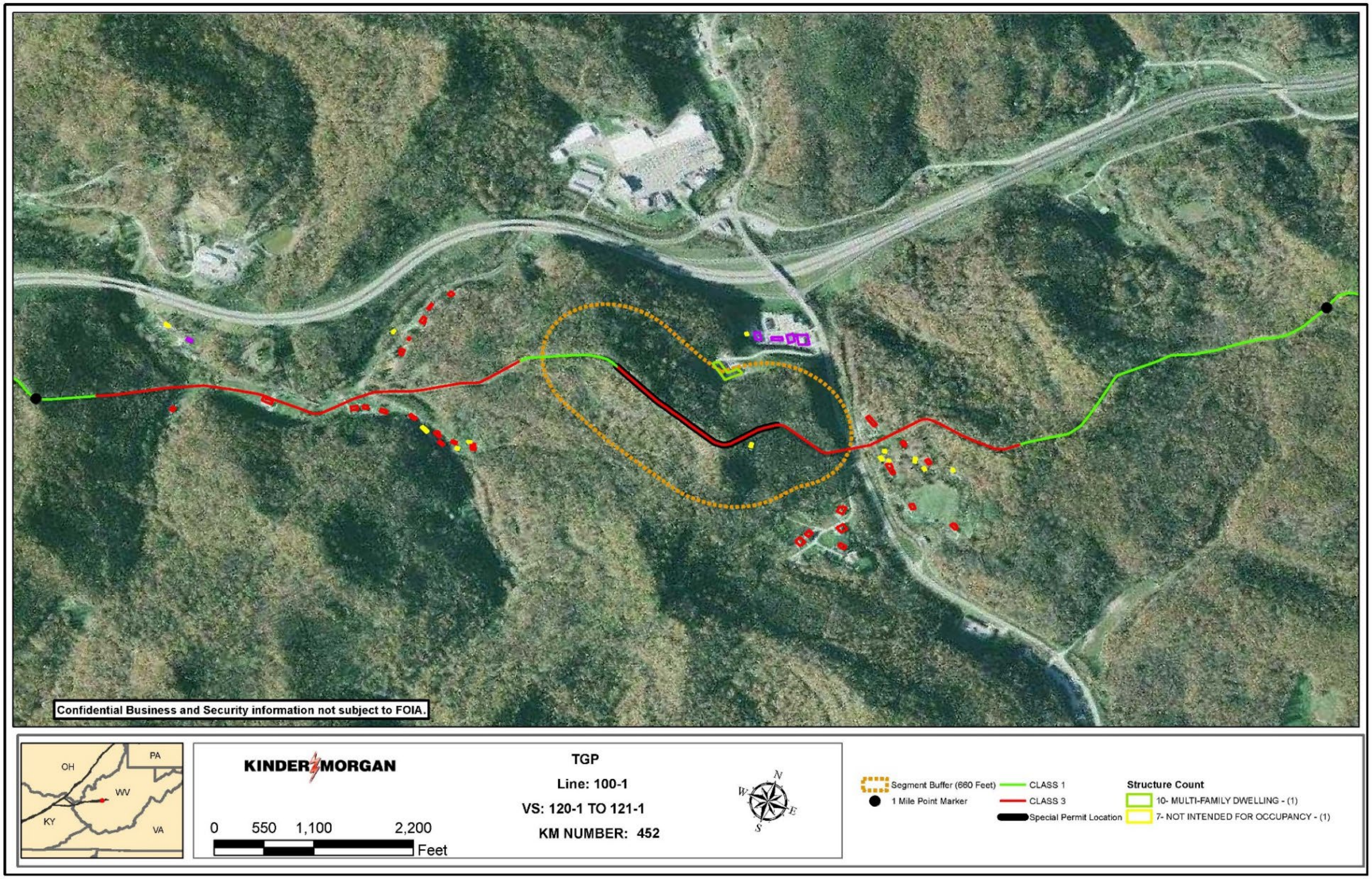
Attachment C – Section 3, ASME B31.8S, 2004

Completed by PHMSA in Washington, DC on: **August 11, 2022**

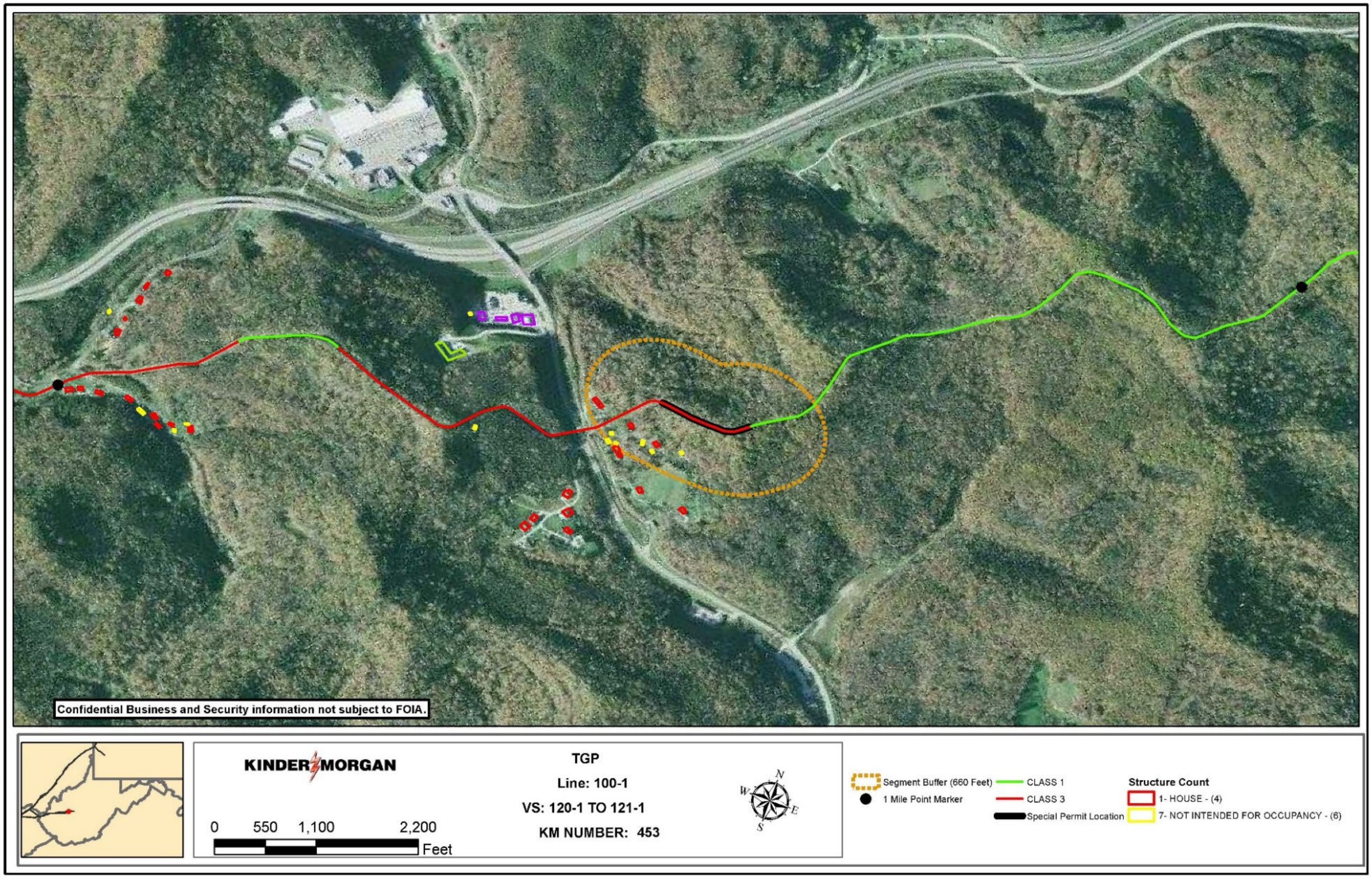
Attachment A-1 - Special Permit Segments and Inspection Area Route Maps



Attachment A-2 - Special Permit Segments and Inspection Area Route Maps



Attachment A-3 - Special Permit Segments and Inspection Area Route Maps



Attachment B

Guidance on Repairs to Interstate Natural Gas Pipelines Pursuant to FERC Regulations

(July 2005)

I. GUIDANCE ON ACTIVITIES ALLOWED UNDER THE FERC REGULATIONS

The guidance we[7] are providing here is to help the interstate natural gas pipeline industry (industry), agencies and other interested parties understand better the expedition of projects under the Pipeline Safety Improvement Act of 2002 (PSIA).[i] This guidance explains which repair projects occurring as a result of the integrity management program require no/or minimal notification to the Federal Energy Regulatory Commission (FERC or Commission) before starting the project, versus those that could require a complete analysis under Commission regulations.

A summary of the potential construction options is provided below: You can access these regulations and the Natural Gas Act through our website at http://www.ferc.gov/legal/ferc-regs.asp (access Title 18 CFR).

- Section 2.55(a) (auxiliary installations)
- Section 2.55(b) (replacement of facilities)
- Blanket Certificate (Subpart F of Part 157)
- Section 7 of the Natural Gas Act (Operation and Maintenance)

II. SUMMARY OF ALLOWABLE ACTIVITIES UNDER FERC PROGRAMS

A. **Operation and Maintenance of Certificated Projects**

Operation and routine maintenance activities can be done without any authorization from FERC beyond the certificate authorizing the construction/operation of the facilities. All the testing including, if necessary, excavating the pipeline for direct inspection can be done if all

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[7] The pronouns we, us, and our refer to the staff of the FERC's Office of Energy Projects.

construction related activities remain in the original right-of-way footprint. If the inspection indicates pipe replacement is needed, then under certain conditions it can be done under the exemption from certificate authorization provided by section 2.55(b) of the regulations (which is explained in detail below in the Summary of FERC Programs). These conditions are:

a. The replaced pipe goes in the same permanent right-of-way as the pipe being replaced.
b. Replacement of the pipeline uses the same construction area that was used in the original installation.
c. The new pipe has substantially equivalent capacity as the replaced pipe.

If these conditions can't be met, then the authorization conferred by the blanket certificate may be able to be used. The blanket certificate program includes conditions requiring consultations with federal agencies for endangered species, essential fish habitat, cultural resources, and coastal zone management concerns among others. The blanket certificate also has project cost limitations.

If the blanket certificate program is used but a variance from a measure in our Plan or Procedures[8] is needed, the company should contact staff immediately so that we can be sure to process a written request quickly. Initial contact information is provided at the end of this guidance. Failure to make this contact can result in a delay.

If the requirements of the blanket program cannot be met, then the company must get a project-specific certificate to authorize the replacement.

None of these regulations exempt the industry from the applicable portions of any other agency's authority. Actions covered by section 2.55(b) are not federal actions by FERC and therefore do not require any FERC involvement in compliance with any regulations such as the Endangered Species Act or the National Historic Preservation Act. However, if these or any other statutes have requirements applicable to non-governmental entities, they still apply. Under the blanket program or the regular certificate process FERC does have an obligation to be involved, either through regulation (the blanket program) or actively in the case of a certificate filing.

8 Plan = Upland Erosion Control, Revegetation and Maintenance Plan. Procedures = Wetland and Waterbody Construction and Mitigation Procedures. These documents can be found at www.ferc.gov/industries/gas/enviro/guidelines.asp

B. **Section 2.55(a) and 2.55(b)**

This section covers installation of auxiliary facilities [2.55(a)] and replacement of facilities [2.55(b)] which are physically deteriorated or obsolete as long as there will be no reduction or abandonment of service through the facilities, and the replacement will have substantially the equivalent design capacity as the original facility. See appendix 1 to this guidance for a description of the kinds of installations which qualify as auxiliary under section 2.55(a).

These 2.55(a) facilities and 2.55(b) replacements are exempt from Natural Gas Act regulations and there are no requirements to comply with standard environmental conditions. However, all replacement facilities must be constructed within the same right-of-way, compressor station, or other aboveground facility site as the facility being replaced. In addition, all construction activity involved with the installation of such replacements must use only the land area originally used for installation of the facilities being replaced. Clarification of the requirement for the use of the same construction area may be found in appendix A to Part 2 of the Commission's regulations. (See appendix 2

to this guidance)

An Annual Report must be filed by May 1 of each year, which identifies all replacement projects completed during the previous calendar year that do not exceed the cost limit specified in column 1 of Table I of 18 CFR section 157.208(d) (less than $8,000,000 in 2005). Replacement projects that exceed this amount require advanced notification to the FERC. Annual reports are not required for projects that require Advance Notification or that only involve aboveground replacement and did not involve compression facilities or the use of earthmoving equipment.

If a replacement project exceeds the cost limitation (over $8,000,000 in 2005), an Advance Notification must be filed at least 30 days before beginning construction (unless immediate replacement is required to comply with U.S. Department of Transportation (DOT) safety regulations).

For both the Annual Report and Advance Notification, the following information must be provided for our review of each project:

- A description of the facilities, including the pipeline length and diameter, capacity and cost, compressor horsepower, metering facilities, taps, valves, etc.;

- The specific reason for replacement of the facilities;
- For 30-day Advance Notifications, a general location map (showing the facilities in relation to existing facilities);
- A current USGS 7.5-minute-series topographic map (showing the location of each facility);
- The actual (or anticipated) start and end dates of construction; and
- A description of the procedures to be used for erosion control, revegetation and maintenance, and stream and wetland crossings (a plan should be submitted, but it does not have to be our recommended Plan and Procedures).

C. **Blanket Certificate - Subpart F of Part 157**

Pipeline integrity repairs, replacements, construction, or abandonment activities which do not meet the requirements of 2.55(a) or 2.55(b) facilities must be authorized under one of several sections of the blanket certificate:

- section 157.208, construction, acquisition, operation, and replacement of any eligible facility or miscellaneous rearrangement of any facilities; or
- section 157.209, temporary compression facilities.

The primary portion of the blanket program which would apply to Integrity Management issues is section 157.208. [9] That section provides for two types of facilities; (1) "eligible" facilities, and (2) "any" facilities.

(1) An "eligible" facility is completely defined in section 157.202. Briefly, it is any facility, other than mainline pipeline and compression facilities, needed to provide service within certificated levels, or facilities to allow the certificate holder to receive gas into its system and interconnections for transporters of gas under Part 284. In addition, it includes any replacement (including mainline) that doesn't qualify under section 2.55 because of incidental increases in capacity or the need to move the facility or use new workspace. Finally, replacements and the modification of facilities (including mainline) to rearrange gas flows or increase compression to restore service in an emergency due to sudden unforeseen damage to mainline facilities are eligible facilities.

If an activity involves an eligible facility or qualifies as a miscellaneous rearrangement, it may proceed under section 157.208 with certain conditions. The blanket certificate program

[9] Sections 157.211, delivery points, and 157.216, abandonment, may in some cases be needed, but would usually be associated with more significant activity under section 157.208.

requires that all projects must be completed in compliance with section 157.206(b). (See further discussion of these standard conditions below.)

(2) The broad category of "any" facility is used in the context of authorization to do miscellaneous rearrangements of "any" facility. This authorization has only one restriction—it doesn't include underground storage injection/withdrawal wells. The blanket allows "miscellaneous rearrangement" of "any" facility where "miscellaneous rearrangement" means relocation or modification that does not result in any change of service, and which is on the same property or is required:

- By highway or dam construction, encroachment of residential, commercial, or industrial areas, erosion, or changes in water courses; or
- To respond to natural forces to ensure safety or maintain operational integrity.

If there is a change of service or something that is other than a simple relocation or modification of an existing facility, then the activity is not a miscellaneous rearrangement. It becomes a construction, acquisition, operation, or replacement which can only be done if the facility is an "eligible" facility.

Minor projects[10] under section 157.208(a) and temporary compression under section 157.209 may be done automatically under the appropriate requirements of those sections. These activities are subject to the Annual Report.

In addition, construction projects under section 157.208 above $8,000,000 require prior notice to the Commission before start of the activity. For these activities, there is a 45day period following the Commission's notice of the Prior Notice filing during which protests of the activity may be filed. If there are no protests, the activity may begin on the 46th day. If there are protests, the activity may not go forward under the blanket regulations unless the protests are withdrawn. If all protests are withdrawn, the activity may proceed on the day following the withdrawal of the last protest. Otherwise, the Commission must issue an Order before the project can be constructed.

[10] Minor projects are those that do not exceed the cost limit specified in column 1 of Table I of 18 CFR section 157.208(d) (less than $8,000,000 in 2005).

The following sections describe the standard environmental conditions which apply to any construction under the blanket program and all the primary requirements for section 157.208 activities.

a) Standard Environmental Conditions for All Blanket Projects

The standard environmental conditions and requirements of section 157.206(b) apply to all projects under the blanket program of Subpart F of Part 157 or to NGPA section 311 facilities used to provide Part 284 transportation, but only if the project involves ground disturbance or changes to operational air or noise emissions. This section of the regulations states that the company will adopt the requirements set forth in section 380.15, Siting and Maintenance Requirements, and "shall issue the relevant portions thereof to construction personnel, with instructions to use them." In addition, it states that all activities will be consistent with all applicable law and the provisions of the following statutes and regulations, or compliance plans developed to implement them.

- Clean Water Act and the National Pollutant Discharge Elimination System Program
- Clean Air Act
- National Historic Preservation Act of 1966 (NHPA)
- Archeological and Historic Preservation Act of 1974
- Coastal Zone Management Act of 1972 (CZM)
- Endangered Species Act of 1973 (ESA)
- Executive Order 11988 (May 24, 1977) requiring federal agencies to evaluate the potential effects of any actions it may take on a floodplain
- Executive Order 11990 (May 24, 1977) requiring an evaluation of the potential effects of construction on wetlands
- Wild and Scenic Rivers Act
- National Wilderness Act
- National Parks and Recreation Act of 1978
- Magnuson-Stevens Fishery Conservation and Management Act

To be in compliance with these statutes under the blanket program for replacements/IM projects which cannot be done under 2.55(b), the project sponsor:

- Must comply with Appendix I of Subpart F, involving consultation with the U.S. Fish and Wildlife Service and/or the U.S. Department of Commerce, National Oceanic and Atmospheric Administration (as appropriate), and the project may go forward only if this consultation results in the agency(ies) concluding that:
  - There are no listed or proposed species or their critical habitat in the project area, or
  - There are listed species or their critical habitat in the project area, but the project is not likely to adversely affect a listed species or its habitat, or
  - There is no need for further consultation
- If protected species or their critical habitat occur within the project area, the project sponsor implements (at its discretion) mitigation resulting from continued consultation with the agency(ies).
- Must comply with Appendix II of Subpart F, involving consultation with the State Historic Preservation Office (SHPO) and/or the Tribal Historic Preservation Officer (THPO) (as appropriate), and this consultation results in the agency(ies) concurring that:
  - No surveys are required, and no eligible properties are in the project area;
  - Surveys are required and that as a result of the surveys no eligible properties are found in the project area; or
  - There are eligible properties in the project area, but the project would have no effect on any such cultural resource property.
- Must obtain the appropriate state agency's determination that the project will comply with the state's coastal zone management plan unless the appropriate state agency waives its right of review, if applicable;
- Must adhere to the Commission staff's current Plan and Procedures, or must obtain staff or appropriate state or federal agency approval to use other specific alternatives;

- Must make sure that the project will not have a significant adverse impact on a sensitive environmental area (see table 1 for the list of sensitive environmental areas from 18 CFR 157.202(b)(11)); and
- Must make sure that the noise attributable to any new compressor station, compression added to an existing station, or any modification, upgrade or update to an existing station does not exceed an L_{dn} of 55 dBA at any noise sensitive area (NSA) (such as schools, hospitals, or residences) unless the NSA is established after facility construction or modification.

If a project cannot meet all of the above conditions, then it is not allowed to proceed under the blanket program. If it is to proceed, a filing must be made to the Commission for a certificate under section 7 of the NGA.

A project is not allowed under the blanket program if the activity is located within 0.5 mile (project authorized under section 157.208 only) of a nuclear power plant which is either operating or under construction, or for which a construction permit has been filed with the Nuclear Regulatory Commission.

Table 1

Sensitive Environmental Areas

The habitats of species which have been identified as endangered or threatened under the Endangered Species Act and Essential Fish Habitat as identified under the Magnuson-Stevens Fishery Conservation and Management Act
National or State Forests or Parks
Properties listed on, or eligible for inclusion in, the National Register of Historic Places, or the National Register of Historic Landmarks
Floodplains and wetlands
Designated or proposed wilderness areas, national or state wild and scenic rivers, wildlife refuges and management areas and sanctuaries
Prime agricultural lands, designated by the Department of Agriculture
Sites which are subject to use by American Indians and other Native Americans for religious purposes

b) Landowner Notification

With two exceptions, landowner notification is required prior to any construction of projects done for the integrity management program under the Subpart F blanket program. One exception is any replacement which is not foreseen and requires immediate attention. Another exception is any replacement which would meet the section 2.55(b) requirements except that the replacement is not of the same capacity.

The definition of "landowner" is found in section 157.6(d)(2). The specific requirements for the contents of the landowner notice are in section 157.203(d).

For automatically authorized projects, landowners must be notified at least 30 days prior to commencing construction or at the time the company initiates easement negotiations, whichever is earlier. A landowner may waive the 30-day prior notice requirement in writing, as long as the notice has been provided.

For projects for which the Commission must receive advance notification, the landowners must be notified within at least three (3) business days following the date that a docket number is assigned to the notice by the Commission, or at the time the company initiates easement negotiations, whichever is earlier.

c) Annual Report for Construction Projects (sections 157.208(a & b) and section 157.209

Projects that qualify for automatic authorization are for (1) projects constructed under section 157.208; (2) do not exceed the cost limit specified in column 1 of Table I of section 157.208(d) (less than $8,000,000 in 2005); and (3) meet the requirements of section 157.209. These projects are reported on an annual basis in an Annual Report that is due by May 1 of each year.

For projects constructed under section 157.208(a) and section 157.209, the annual report must provide a description of the contacts made, reports produced, and results of consultations completed before construction to comply with the ESA, NHPA, and CZM. The annual report must also provide the date and name of the agency that cleared the project. Actual documentation is not required, although it is helpful to include the "clearance" from the agency.

Projects conducted under section 157.208(b) also must be included in the annual report. However, since environmental information was provided in the notice filed prior to construction, no additional environmental information is required for the annual report.

d) Contents of a Prior Notice Filing Under section 157.208(b)

Projects that require prior notice under section 157.208(b) are those that cost more than the limitations set forth in column 1 but less than the amount specified in column 2 of Table I in section 157.208(d) (from $8,000,000 to $22,000,000 in 2005). For these projects, a concise analysis of the relevant issues outlined in section 380.12 is required in addition to a general description of the activity that is to take place. For projects to be completed under this section, include the following environmental information for each project:

- A description of the facilities, including the length and diameter, wall thickness and maximum allowable operating pressure of the pipeline; for compressors, the size, type and number of compressor units, horsepower required, horsepower existing and proposed, volume of fuel gas, suction and discharge pressure and compression ratios; metering facilities, taps, valves, etc.;
- The specific purpose of the facilities and relationship to other existing and planned facilities;
- A general location map (showing the facilities in relation to existing facilities);
- USGS 7.5-minute-series topographic maps or maps of equivalent detail (showing the location of each facility) and any sensitive environmental area within 0.25 mile of construction;
- The anticipated start and end dates of construction;
- A concise analysis summarizing the existing environmental conditions, the anticipated significant impacts as a result of construction of the facilities, and mitigation measures proposed to reduce or avoid impact on the quality of the human environment, including impact on sensitive environmental areas;
- A statement that the project will comply with the requirements of section 157.206(b), including for compression facilities, the Clean Air Act and the applicable state implementation plans developed under the Clean Air Act, and the Ldn of 55 dBA at any NSA;

- Copies of correspondence or documentation of consultation with the FWS, SHPO, and appropriate state coastal zone management agency as described above under reporting requirements for Annual Reports; and
- Copies of all agreements received to comply with the ESA, the NHPA, and the CZM.

e) Additional Projects that could occur as a result of the Integrity Management Program

Potentially delivery point and abandonment projects could occur in relation to integrity management repairs/replacements, if so then the regulations in section 157.211 and section 157.216 must be followed.

Installation of delivery points under section 157.211(a)(1), and abandonment under section 157.216(a), may be done automatically under the appropriate requirements of those sections. Projects that qualify for automatic authorization are those that meet the applicable subsections of section 157.211 or section 157.216. These projects are reported on an annual basis in an Annual Report that is due by May 1 of each year. For section 157.211 and for section 157.216, if earth disturbance was involved, only the date of the "clearance" is required.

Activities which require prior notice include the installation of delivery points under section 157.211(a)(2), and abandonment under section 157.216(b).

f) Prior Notice Filings under section 157.211(a)(2) and section 157.216(b)

Although the regulations do not specifically require the filing of environmental information for construction or abandonment of facilities under these sections (other than USGS maps), the standard environmental conditions of section 157.206(b) apply to these projects. However, the following environmental information will assist us in our review:

- A description of the activity and its purpose;
- The anticipated start and end dates of activity;
- The county and state where the activity will take place;
- A general location map of where the activity will take place (copies of pipeline system maps or USGS topographic maps are acceptable provided that enough detail is included to allow us to locate the facilities in the field);

- A statement that the project will comply with the requirements of section 157.206(b) before construction; and
- Copies of correspondence or documentation of consultation (e.g., telephone conversations or meetings) with the:
  - FWS and NMFS (see Appendix I of Subpart F, referenced at section 156.206(b)(3)(i));
  - SHPO and THPO (see Appendix II of Subpart F, referenced at section 156.206(b)(3)(ii)); and
- Consistency determination from the appropriate agency that administers the state's coastal zone management plan, if applicable.

D. **Where to go for questions**

Contact: Mr. Douglas A. Sipe

Project Manager, Gas Branch 2

douglas.sipe@ferc.gov

202.502.8837

Or

Mr. John S. Leiss

Chief, Gas Branch 2
john.leiss@ferc.gov

202.502.8058

Federal Energy Regulatory Commission

888 First Street, NE

Washington DC 20426

i. On November 15, 2002, Congress passed the Pipeline Safety Improvement Act of 2002 (PSIA), which was signed into law on December 17, 2002, and codified at 49 U.S.C. 60109. This law requires the Research and Special Programs Administration/Office of Pipeline Safety of the DOT to ''issue regulations prescribing standards to direct an operator's conduct of a risk analysis and adoption and implementation of an integrity management program'' no later than 12 months after December 17, 2002. The statute sets forth minimum requirements for integrity management programs for gas pipelines located in HCAs.

The final DOT regulations require operators to develop integrity management programs for gas transmission pipelines located where a leak or rupture could do the most harm, i.e., could impact HCAs. The rule requires gas transmission pipeline operators to perform ongoing assessments of pipeline integrity, to improve data collection, integration, and analysis; to repair and remediate the pipeline as necessary; and to implement preventive and mitigative actions. The regulations comprehensively address statutory mandates, safety recommendations, and conclusions from accident analyses, all of which indicate that coordinated risk control measures are needed to improve pipeline safety.

The PSIA directed federal agencies and departments having jurisdiction over the permitting of work needed for pipeline repairs to establish a coordinated and expedited pipeline repair permit review process. The process must be designed to enable pipeline operators to commence and complete all activities necessary to carry out pipeline repairs within the time periods to be established and specified by the Secretary of Transportation, pursuant to the PSIA, and in accordance with the statutory and regulatory requirements of the other agencies.

In accordance with Section 16 of the PSIA, to carry out this mandate and in recognition of the fact that timely repair of both natural gas and hazardous liquid pipelines is essential to facilitate the nation's ability to meet the goal of sufficient availability and use of natural gas and liquid fuels, several federal agencies have entered into a Memorandum of Understanding (MOU). Agencies who signed the MOU are: Council on Environmental Quality; DOT; Environmental Protection Agency; Department of the Interior; Department of Commerce; Department of Defense; FERC; Department of Agriculture; Department of Energy; and the Advisory Council on Historic Preservation.

Appendix 1:
2.55(a) Auxiliary Facilities

(a) Auxiliary installations.

(1) Installations (excluding gas compressors) which are merely auxiliary or appurtenant to an authorized or proposed transmission pipeline system, and which are

installations only for the purpose of obtaining more efficient or more economical operation of the authorized or proposed transmission facilities, such as: Valves; drips; pig launchers/receivers; yard and station piping; cathodic protection equipment; gas cleaning, cooling and dehydration equipment; residual refining equipment; water pumping, treatment and cooling equipment; electrical and communication equipment; and buildings.

Appendix 2:

Appendix A to Part 2--Guidance for Determining the Acceptable Construction Area for Replacements

These guidelines shall be followed to determine what area may be used to construct the replacement facility. Specifically, they address what areas, in addition to the permanent right-of-way, may be used.

Pipeline replacement must be within the existing right-of-way as specified by Sec.

2.55(b)(1)(ii). Construction activities for the replacement can extend outside the current permanent right-of-way if they are within the temporary and permanent right-of-way and associated work spaces used in the original installation.

If documentation is not available on the location and width of the temporary and permanent rights-of-way and associated work space that was used to construct the original facility, the company may use the following guidance in replacing its facility, provided the appropriate easements have been obtained:

a. Construction should be limited to no more than a 75-foot-wide right-of-way including the existing permanent right-of-way for large diameter pipeline (pipe greater than 12 inches in diameter) to carry out routine construction. Pipeline 12 inches in diameter and smaller should use no more than a 50-foot-wide right-of-way.
b. The temporary right-of-way (working side) should be on the same side that was used in constructing the original pipeline.
c. A reasonable amount of additional temporary work space on both sides of roads and interstate highways, railroads, and significant stream crossings and in side slope areas is

allowed. The size should be dependent upon site-specific conditions. Typical work spaces are:

ITEM	Typical extra area (width/length)
Two lane road (bored)	25-50 by 100 feet
Four lane road (bored)	50 by 100 feet
Major river (wet cut)	100 by 200 feet
Intermediate stream (wet cut)	50 by 100 feet
Single railroad track	25-50 by 100 feet

d. The replacement facility must be located within the permanent right-of-way or, in the case of nonlinear facilities, the cleared building site. In the case of pipelines this is assumed to be 50-feet-wide and centered over the pipeline unless otherwise legally specified.

However, use of the above guidelines for work space size is constrained by the physical evidence in the area. Areas obviously not cleared during the original construction, as evidenced by stands of mature trees, structures, or other features that exceed the age of the facility being replaced, should not be used for construction of the replacement facility.

If these guidelines cannot be met, the company should consult with the Commission's staff to determine if the exemption afforded by Sec. 2.55 may be used. If the exemption may not be used, construction authorization must be obtained pursuant to another regulation under the Natural Gas Act.

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keep the public informed about their integrity management efforts. This plan shall provide information to be communicated to each stakeholder about the integrity plan and the results achieved. Paragraph 10 provides further information about communications plans.

2.4.4 Management of Change Plan. Pipeline systems and the environment in which they operate are seldom static. A systematic process shall be used to ensure that, prior to implementation, changes to the pipeline system design, operation, or maintenance are evaluated for their potential risk impacts, and to ensure that changes to the environment in which the pipeline operates are evaluated. After these changes are made, they shall be incorporated, as appropriate, into future risk assessments to ensure that the risk assessment process addresses the systems as currently configured, operated, and maintained. The results of the plan's mitigative activities should be used as a feedback for systems and facilities design and operation. Paragraph 11 discusses the important aspects of managing changes as they relate to integrity management.

2.4.5 Quality Control Plan. Paragraph 12 discusses the evaluation of the integrity management program for quality control purposes. That paragraph outlines the necessary documentation for the integrity management program. The paragraph also discusses auditing of the program, including the processes, inspections, mitigation activities, and prevention activities.

3 CONSEQUENCES

3.1 General

Risk is the mathematical product of the likelihood (probability) and the consequences of events that result from a failure. Risk may be decreased by reducing either the likelihood or the consequences of a failure, or both. This paragraph specifically addresses the consequence portion of the risk equation. The operator shall consider consequences of a potential failure when prioritizing inspections and mitigation activities.

The B31.8 Code manages risk to pipeline integrity by adjusting design and safety factors, and inspection and maintenance frequencies, as the potential consequences of a failure increase. This has been done on an empirical basis without quantifying the consequences of a failure.

Paragraph 3.2 describes how to determine the area that is affected by a pipeline failure (potential impact area) in order to evaluate the potential consequences of such an event. The area impacted is a function of the pipeline diameter and pressure.

3.2 Potential Impact Area

The refined radius of impact for natural gas is calculated using the formula

$$r = 0.69 \cdot d\sqrt{p} \qquad (1)$$

where

d = outside diameter of the pipeline, in.
p = pipeline segment's maximum allowable operating pressure (MAOP), psig
r = radius of the impact circle, ft

EXAMPLE: A 30 in. diameter pipe with a maximum allowable operating pressure of 1,000 psig has a potential impact radius of approximately 660 ft.

$$\begin{aligned} r &= 0.69 \cdot d\sqrt{p} \\ &= 0.69\ (30\text{ in.})(1{,}000\text{ lb/in.}^2)^{1/2} \\ &= 654.6\text{ ft} \approx 660\text{ ft} \end{aligned}$$

Use of this equation shows that failure of a smaller diameter, lower pressure pipeline will affect a smaller area than a larger diameter, higher pressure pipeline. (See GRI-00/0189.)

NOTE: 0.69 is the factor for natural gas. Other gases or rich natural gas shall use different factors.

Equation (1) is derived from

$$r = \sqrt{\frac{115{,}920}{8} \cdot \mu \cdot \chi_g \cdot \lambda \cdot C_d \cdot H_C \cdot \frac{Q}{a_o} \cdot \frac{pd^2}{I_{th}}}$$

where

C_d = discharge coefficient
H_C = heat of combustion
I_{th} = threshold heat flux
Q = flow factor $= \gamma\left(\frac{2}{\gamma+1}\right)^{\frac{\gamma+1}{2(\gamma-1)}}$
R = gas constant
T = gas temperature
a_o = sonic velocity of gas $= \sqrt{\frac{\gamma RT}{m}}$
d = line diameter
m = gas molecular weight
p = live pressure
r = refined radius of impact
γ = specific heat ratio of gas
λ = release rate decay factor
μ = combustion efficiency factor
χ_g = emissivity factor

In a performance-based program, the operator may consider alternate models that calculate impact areas and consider additional factors, such as depth of burial, that may reduce impact areas. The operator shall count the number of houses and individual units in buildings within the potential impact area. The potential impact area extends from the center of the first affected circle to the center of the last affected circle (see Fig. 3). This housing unit count can then be used to help determine the relative consequences of a rupture of the pipeline segment.

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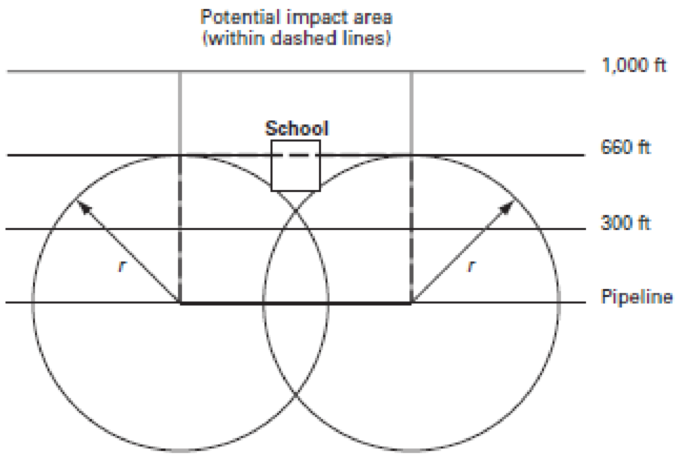

GENERAL NOTE: This diagram represents the results for a 30 in. pipe with an MAOP of 1,000 psig.

Fig. 3 Potential Impact Area

The ranking of these areas is an important element of risk assessment. Determining the likelihood of failure is the other important element of risk assessment (see paras. 4 and 5).

3.3 Consequence Factors to Consider

When evaluating the consequences of a failure within the impact zone, the operator shall consider at least the following:

(a) population density

(b) proximity of the population to the pipeline (including consideration of manmade or natural barriers that may provide some level of protection)

(c) proximity of populations with limited or impaired mobility (e.g., hospitals, schools, child-care centers, retirement communities, prisons, recreation areas), particularly in unprotected outside areas

(d) property damage

(e) environmental damage

(f) effects of unignited gas releases

(g) security of gas supply (e.g., impacts resulting from interruption of service)

(h) public convenience and necessity

(i) potential for secondary failures

Note that the consequences may vary based on the richness of the gas transported and as a result of how the gas decompresses. The richer the gas, the more important defects and material properties are in modeling the characteristics of the failure.

4 GATHERING, REVIEWING, AND INTEGRATING DATA

4.1 General

This paragraph provides a systematic process for pipeline operators to collect and effectively utilize the data elements necessary for risk assessment. Comprehensive pipeline and facility knowledge is an essential component of a performance-based integrity management program. In addition, information on operational history, the environment around the pipeline, mitigation techniques employed, and process/procedure reviews is also necessary. Data are a key element in the decision-making process required for program implementation. When the operator lacks sufficient data or where data quality is below requirements, the operator shall follow the prescriptive-based processes as shown in Nonmandatory Appendix A.

Pipeline operator procedures, operation and maintenance plans, incident information, and other pipeline operator documents specify and require collection of data that are suitable for integrity/risk assessment. Integration of the data elements is essential in order to obtain complete and accurate information needed for an integrity management program.

4.2 Data Requirements

The operator shall have a comprehensive plan for collecting all data sets. The operator must first collect the data required to perform a risk assessment (see para.

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