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

Preliminary
Regulatory Impact Analysis

Pipeline Safety: Class Location Change Requirements
Notice of Proposed Rulemaking

August 2020

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Executive Summary

The Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) is proposing changes to the Federal Pipeline Safety Regulations in title 49 of the Code of Federal Regulations (CFR) part 192 relating to class location requirements.

ES-1 Purpose of the Proposed Rule

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Pipeline Safety Act)[1] mandated that PHMSA evaluate whether integrity management (IM) principles should be expanded beyond high consequence areas (HCA), and whether expanding IM principles (IMP) beyond HCAs with respect to transmission pipelines would mitigate the need for class location requirements. It also required PHMSA to provide a report to Congress summarizing its evaluation and findings. The 2011 Pipeline Safety Act also required that, should PHMSA's evaluation conclude that IMP should be expanded beyond HCAs and applying IMP to transmission pipelines located areas outside of HCAs would mitigate the need for class location requirements, PHMSA issue final regulations accordingly.

Class locations are used in the natural gas pipeline safety regulations in a graded approach to provide more conservative safety margins and safety standards commensurate with the potential consequences based on the population density near a pipeline. An onshore gas transmission pipeline's class location can change as the population living or working near a pipeline grows. A change in class location requires operators to confirm operating safety factors and to recalculate and adjust the maximum allowable operating pressure (MAOP) of the pipeline through lowering the MAOP, pressure testing, or replacement using pipe with an appropriate safety factor for the population growth.

Some operators have applied for special permits to prevent the need for pipe replacement or pressure reduction after a class location change. Under the special permit process, PHMSA waives or otherwise modifies compliance with regulatory requirements if the special permit (including any safety conditions imposed) would be consistent with pipeline safety.

On July 31, 2018, PHMSA published an advance notice of proposed rulemaking (ANPRM) in the Federal Register to seek feedback and comments regarding the revision of the Federal pipeline safety regulations applicable to the management of class location change segments on gas transmission pipelines.[2] Specifically, PHMSA requested comments regarding whether the current requirements of managing class location changes should be modified to allow for Integrity Management (IM) activities in lieu of the current required activities (e.g. pipe replacement, pressure test, or pressure reduction) and whether that modification would mitigate the public safety need for the existing class location requirements.

Based on input from previous public meetings and workshops,[3] the comments received on the ANPRM, the findings of the 2016 report to Congress required by the 2011 Pipeline Safety Act,[4] and a

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[1] Pub. L. 112-90, 125 Stat. 1904.

[2] "Pipeline Safety: Class Location Change Requirements," 83 FR 36861 (July 31, 2018), Docket No. PHMSA-2017-0151-0002.

[3] See https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=95.

[4] PHMSA, *Evaluation of Expanding Pipeline Integrity Management Beyond High-Consequence Areas and Whether Such Expansion Would Mitigate the Need for Gas Pipeline Class Location Requirements*, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/news/55521/report-congress-evaluation-expanding-pipeline-imp-hcas-full.pdf ("2016 Class Location Report").

review of PHMSA's active special permits for Class 1 to Class 3 location changes,[5] PHMSA determined that the application of IMP to gas transmission pipelines outside of the HCA would not warrant the elimination of class location requirements.[6] However, in reviewing those materials, PHMSA concluded that adjustments to class location requirements are necessary to protect public safety and the environment. The NPRM consequently proposes to amend the class location regulations for some in-service gas transmission segments where the class location would change from Class 1 to Class 3. Transmission pipelines that have experienced a class-location change would be able to include an IM type option and implement other defined pipeline safety measures, as further discussed in the NPRM. This preliminary regulatory impact analysis (PRIA) presents PHMSA's estimates of the costs and benefits of the proposed action, and PHMSA seeks comment on the proposed action and estimated cost savings described herein.

With this NPRM, PHMSA is proposing to add a new method of compliance to the existing four options for future Class 1 to Class 3 ("C1 to C3") location segment changes. The proposed rule option would maintain pipeline safety while providing additional flexibility for eligible C1 to C3 changes that is similar to the approach taken in the current Special Permit program and its associated requirements, which are focused on integrity management program (IMP) practices. PHMSA has granted Special Permits to operators allowing the management of class location changes using IM type practices in lieu of compliance with the current regulations since 2004.

ES-2 Costs, Cost Savings and Benefits

The proposed rule is a significant regulatory action within the scope of section 3(f)(4) of Executive Order 12866. This PRIA fulfills the requirements in section 6(a)(3)(B) of Executive Order 12866 to prepare an assessment of the economic impacts of the rule. It also meets PHMSA's statutory requirement for risk analysis for new rules (49 U.S.C. 60101 et. seq.), and DOT policies and procedures (49 CFR part 5). Additionally, the Initial Regulatory Flexibility Analysis (IRFA) is incorporated as part of the PRIA for this rule, and a preliminary Environmental Assessment (EA) is included in the docket.

Gas transmission pipelines are divided into classes from 1 to 4 based on the number of buildings or dwellings for human occupancy located in proximity to the pipeline. The proposed rule applies to pipeline segments changing from a C1 to C3 location, and therefore the rule would affect a small fraction of the current Class 1 pipelines, which comprise nearly 80 percent of all onshore gas transmission pipelines, that could change to Class 3.

The baseline case accounts for the practices and standards implemented by pipeline operators under existing regulations. Estimating costs and benefits requires estimating the following inputs: (a) the quantity of miles changing from Class 1 to Class 3 annually, (b) the utilization rate and unit cost for currently available compliance methods, particularly pipe replacement, (c) the unit costs of complying with the Special Permit program, and (d) the mix of consequence classifications among affected segments.

PHMSA is proposing that, in order for pipe segment to be eligible for the rule option, the C1 to C3 location segment change must occur after the effective date of rule. The regulatory analysis therefore requires an estimate of class location changes from C1 to C3. Using Annual Report data, PHMSA's

[5] As of May 1, 2019, PHMSA's 12 special permits for Class 1 to Class 3 location changes apply to segments in the following 17 States: Alabama, Arizona, Colorado, Georgia, Kentucky, Louisiana, Michigan, Mississippi, New Jersey, New Mexico, New York, Ohio, Pennsylvania, Tennessee, Texas, West Virginia, and Wyoming.

[6] See 2016 Class Location Report at 43.

regulatory impact analysis assumes that the number of miles changing from C1 to C3 each year is a constant value.

The new compliance method causes the utilization of the baseline compliance methods to change, and produces a notable shift from pipe replacement to the new compliance method. Exhibit ES-1 and Exhibit ES-2 summarize these changes for two different class-change activity levels.

The proportion of C1 to C3 location changes managed using pipe replacement decreases from 86 to 90 percent in the baseline to 57 to 59 percent under the proposed rule, as estimated in Section 4.1. Similarly, the vast majority of current users of the Special Permit program would switch to the new proposed rule method. In the baseline, PHMSA estimates that 7 to 11 percent of C1 to C3 changes are managed using a special permit, whereas under the proposed rule, PHMSA estimates 2 to 3 percent of miles would use a special permit. These estimates are based on PHMSA's assessment of Class 1 pipelines that could qualify for the proposed rule option. The compliance approach for operators that use the pressure reduction or MAOP reconfirmation method to manage the class location change does not change due to the proposed rule. PHMSA presents two estimates in this analysis describing the number of miles that change from C1 to C3 each year. PHMSA uses a range of class change activity due to uncertainty in the underlying data and estimates, as detailed in Section 3.1.

Scenario 1 is predicated on a baseline estimate of pipeline replacement due to class-change of 66.8 miles per year, and total class change miles of 77.6. This value is the average of annual pipeline replacements due to class-change from 2011 to 2017 estimated from public comments.[7] Scenario 2 is based on a projected baseline pipeline replacement rate of 105.6 miles per year estimated from the projection provided in the same public comments, and total class change miles of 117.6. Based on an average segment length of approximately 0.26 miles, and assuming one excavation per segment, PHMSA estimates between 257 to 406 excavations in the baseline. These class change rates were validated by PHMSA in an analysis of historical Annual Report data from 2010 to 2017. This analysis, described in Appendix B, PHMSA estimated a lower bound on the annual average of 39.5 miles per year and an upper bound of 354.9 miles per year.

Exhibit ES-1: Scenario 1 Compliance Method Utilization Rates and Mileage for C1 to C3 Changes: Baseline vs. Proposed Rule

	Baseline		***Proposed Rule***		
Compliance Method	**Compliance Utilization Rate**	**Annual C1 to C3 Miles**	**Compliance Utilization Rate**	**Annual C1 to C3 Miles**	**Change from Baseline (miles)**
Pressure Test	1.5%	1.2	1.5%	1.2	0
MAOP Reduction	1.5%	1.2	1.5%	1.2	0
Special Permit	10.9%	8.4	3.0%	2.3	-6.1
Pipe Replacement	86.1%	66.8	56.6%	43.9	-22.9
New Compliance Method	0%	0	37.4%	29.0	29.0
Total	**100%**	**77.6**	**100%**	**77.6**	**0**
	Baseline		**Proposed Rule**		

[7] Data in Table 2 of Comments on Pipeline Safety: Class Location Change Requirements, American Gas Association, American Petroleum Institute, American Public Gas Association, and Interstate Natural Gas Association of America, October 1, 2018, Docket No. PHMSA-2017-0151. The pipeline replacement mileages reported for participating Association members were scaled up to an estimate of all transmission pipelines assuming the reported data is a valid estimate of replacements per mile of all transmission pipelines.

Exhibit ES-2: Scenario 2 Compliance Method Utilization Rates and Mileage for C1 to C3 Changes: Baseline vs. Proposed Rule

	Baseline		*Proposed Rule*		
Compliance Method	**Compliance Utilization Rate**	**Annual C1 to C3 Miles**	**Compliance Utilization Rate**	**Annual C1 to C3 Miles**	**Change from Baseline (miles)**
Pressure Test	1.5%	1.8	1.5%	1.8	0
MAOP Reduction	1.5%	1.8	1.5%	1.8	0
Special Permit	7.2%	8.4	2.0%	2.3	-6.1
Pipe Replacement	89.8%	105.6	59.0%	69.4	-36.2
New Compliance Method	0%	0	36.0%	42.3	42.3
Total	**100%**	**117.6**	**100%**	**117.6**	**0**

Consistent with the changes in mileage by method, the cost savings this rule would generate are driven almost entirely by the switch from pipe replacement to the proposed rule method.

Exhibit ES-3 and Exhibit ES-4 present total and annualized costs for mileage Scenario 1, and Exhibit ES-5 and Exhibit ES-6 present results for mileage Scenario 2. PHMSA estimates annualized cost savings of approximately $54 to $55 million for Scenario 1, and $84 to $86 million for Scenario 2, based on 3 and 7 percent discount rates. The difference in cost savings between these two scenarios is proportional to the difference in total affected miles of pipeline year (i.e., 77.6 versus 117.6). Virtually all of the cost savings arise from avoided pipe replacements. The proposed rule would not impose any new costs to the pipeline company owners and operators.

Summary of Cost Savings, Scenario 1

Exhibit ES-3 and Exhibit ES-4 show the total and annualized proposed rule cost savings from 2020 to 2039 for Scenario 1, which is based on a total annual activity level of 77.6 miles per year.

Exhibit ES-3: Total Proposed Rule Cost Savings, Scenario 1 (NPV, 2020 to 2039, millions)

	Discount Rate	
Baseline	**3%**	**7%**
Pipe Replacement	$3,075	$2,190
Special Permits	$134	$85
Total Cost	**$3,209**	**$2,275**
Proposed Rule	**3%**	**7%**
Pipe Replacement	$2,020	$1,439
Special Permits	$37	$24
New Compliance Method	$354	$231
Total Cost	**$2,412**	**$1,693**
Net Total Cost	**-$797**	**-$582**

Exhibit ES-4: Annualized Proposed Rule Cost Savings, Scenario 1 (2020 – 2039, millions)

	Discount Rate	
Baseline*	**3%**	**7%**
Pipe Replacement	$206.7	$206.7
Special Permits	$9.0	$8.0
Total Cost	**$215.7**	**$214.7**
Proposed Rule	**3%**	**7%**
Pipe Replacement	$135.8	$135.8
Special Permits	$2.5	$2.2
New Compliance Method	$23.8	$21.8
Total Cost	$162.1	$159.8
Net Annualized Cost	**-$53.6**	**-$54.9**

*Operators also have the option to use a pressure test or pressure reduction to manage the class location change. To the extent operators find the new class location MAOP acceptable, the decision by operators to use these options is not affected by the addition of the proposed rule compliance method. Therefore, the rule has no incremental effect on these compliance options.

Summary of Cost Savings, Scenario 2

Exhibit ES-5 and Exhibit ES-6 show the total and annualized proposed rule cost savings from 2020 to 2039 for Scenario 2, which is based on 117.6 miles of affected activity per year.

Exhibit ES-5: Total Proposed Rule Cost Savings, Scenario 2 (NPV, 2020 to 2039, millions)

	Discount Rate	
Baseline	**3%**	**7%**
Pipe Replacement	$4,860	$3,461
Special Permits	$134	$85
Total Cost	**$4,994**	**$3,546**
Proposed Rule	**3%**	**7%**
Pipe Replacement	$3,193	$2,274
Special Permits	$37	$24
New Compliance Method	$517	$337
Total Cost	**$3,747**	**$2,635**
Net Total Cost	**-$1,246**	**-$911**

Exhibit ES-6: Annualized Proposed Rule Cost Savings, Scenario 2 (2020 – 2039, millions)

	Discount Rate	
Baseline*	**3%**	**7%**
Pipe Replacement	$326.7	$326.7
Special Permits	$9.0	$8.0
Total Cost	**$335.7**	**$334.7**
Proposed Rule	**3%**	**7%**
Pipe Replacement	$214.6	$214.6
Special Permits	$2.5	$2.2
New Compliance Method	$34.8	$31.8
Total Cost	$251.9	$248.7
Net Annualized Cost	**-$83.8**	**-$86.0**

* Operators also have the option to use a pressure test or pressure reduction to manage the class location change. To the extent operators find the new class location MAOP acceptable, the decision by operators to use these options is not affected by the addition of the proposed rule compliance method. Therefore, the rule has no incremental effect on these compliance options.

The cost savings the proposed rule would generate are driven almost entirely by the switch from pipe replacement to the proposed rule method, and the overall lower cost of compliance for the proposed rule option, compared to pipe replacement. Exhibit ES-7 summarizes annualized compliance costs on a per-mile basis for the three compliance options included in the analysis.[8]

Exhibit ES-7: Annualized Cost per Mile for Class Change Compliance Methods (2020 – 2039)

Compliance Option	Annualized Cost per Mile	
	3% Discount Rate	**7% Discount Rate**
Pipe Replacement	$3,092,493	$3,092,483
Special Permit	$1,068,130	$954,937
New Compliance Option	$819,967	$750,671

[8] The special permit option and new compliance option include a mix of one-time, annual, and otherwise recurring costs (e.g., every five years), so compliance cost outlays are not uniform in each year. The annualized costs presented converts this "lumpy" time-series of cost outlays into an annual equivalent value for the purposes of comparison across options. Annualized costs capture, but do not explicitly show, differences in the mix of one-time and other costs that comprise the full cost of compliance over the 20-year analysis period. For example, as detailed in this RIA, although the new compliance option is less expensive than the special permit overall on an annualized basis, the rule option includes more up-front costs than the special permit option, but less in the way of recurring cost.

1 Introduction

The PHMSA OPS is proposing changes to the Federal Pipeline Safety Regulations in 49 CFR part 192, *Pipeline Safety: Class Location Requirements*.

This rule affects existing class location requirements for natural gas transmission pipelines, specifically as they pertain to actions pipeline operators are required to take following class location changes due to population growth near the pipeline. Operators have suggested that performing integrity management measures on pipelines where class locations have changed due to population increases would be an equally safe but less costly alternative to the current requirements of either reducing pressure, pressure testing, or replacing pipe. This proposed rule reflects the findings of a Notice of Inquiry published in 2013,[9] an ANPRM published on July 31, 2018, and the 2016 Class Location Report, regarding whether to revise current class location change regulations to include an alternative method beyond the four methods that are available to operators: 1) Pressure reduction, 2) Pressure testing, 3) Pipe replacement, and 4) the Special Permit program for class changes.

With this rule, PHMSA is proposing to add a new method of compliance to the existing four options for future C1 to C3 location segment changes. The proposed rule option would maintain pipeline safety while reducing regulatory burden and providing additional flexibility for operators by codifying a new compliance method – for eligible C1 to C3 changes – that is similar to the current Special Permit program. PHMSA developed its class location Special Permit process by adapting IM concepts and through implementation of the published typical considerations for class location change special permit requests in the Federal Register in 2004.

The preamble that accompanies the publication of the proposed rule in the Federal Register provides more details on the context for the rulemaking, including stakeholder input, and the rationale for the requirements.

This PRIA fulfills the requirements of Executive Orders 12866 to prepare an assessment of economic impacts of the rule. It also meets PHMSA's statutory requirement for risk analysis for new rules (49 U.S.C. 60101 et. seq.) and DOT policies and procedures for rulemakings (49 CFR part 5). PHMSA also has prepared an IRFA, which is incorporated as part of the PRIA for this rule, and a preliminary Environmental Assessment (EA), which is included in the docket.

1.1 Regulatory Background

The 2011 Pipeline Safety Act required that PHMSA evaluate whether IM should be expanded beyond HCAs and whether such expansion would mitigate the need for class location requirements.[10] Section 5 of the 2011 Pipeline Safety Act requires PHMSA to report to Congress its evaluation findings and issue regulations in accordance with its reported findings, following a prescribed review period.

On August 1, 2013, PHMSA published a Notice of Inquiry in the Federal Register soliciting comments on whether expanding gas IM program requirements would mitigate the need for class location requirements in line with the Section 5 mandate of the 2011 Pipeline Safety Act.[11] This was followed in 2014 by a PHMSA sponsored Class Location Workshop to solicit comments on whether applying

[9] 78 FR 46560 (August 1, 2013), Docket No. PHMSA–2013–0161.
[10] 49 U.S.C. 60109 Note.
[11] 78 FR 46560 (August 1, 2013).

the gas pipeline IM program requirements beyond HCAs would mitigate the need for gas pipeline class location requirements.[12]

PHMSA subsequently produced the 2016 Class Location Report to Congress.

On July 31, 2018, PHMSA published an ANPRM in the Federal Register, "Pipeline Safety: Class Location Change Requirements," initiating this rulemaking and seeking comment on existing class location requirements for natural gas transmission pipelines pertaining to actions operators are required to take following class location changes due to population growth.

1.2 Need for Action

The 2011 Pipeline Safety Act mandated that PHMSA evaluate whether IMP should be expanded beyond HCAs, and whether expanding IMP beyond HCAs with respect to gas transmission pipelines would mitigate the need for class location requirements. It also required PHMSA to provide a report to Congress, summarizing its evaluation and findings. In the event the evaluation concludes that IMP should be expanded beyond HCAs and applying IMP to transmission pipelines located areas outside of HCAs would mitigate the need for class location requirements, PHMSA must issue final regulations accordingly.

The rule is also consistent with the objectives of DOT regulatory policies and procedures at 49 CFR part 5, and PHMSA's regulatory agenda and objectives, which include a commitment to reducing unnecessary burdens while ensuring safety of the pipeline system.

[12] Meeting presentations are available online at: http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=95 and Docket No. PHMSA-2013-0161.

2 Summary of the Proposed Rule

The class location concept pre-dates Federal regulation of gas transmission pipelines. The original part 192 regulations from 1970 contained class location requirements developed by ASME[13] and incorporated into its standards. Since that time, PHMSA has included class location as an integral part of pipeline safety regulations. The classes use a risk-based approach that requires an incrementally higher safety margin commensurate with population density. Class locations are central to establishing minimum safety standards for MAOPs, design pressures, pipe wall thickness, valve spacing, and O&M inspection, surveillance, and repair intervals.

Gas transmission pipelines are divided into classes from 1 to 4 based on the number of buildings or dwellings for human occupancy located in proximity to the pipeline. Pipeline class locations for onshore gas pipelines are determined as specified in 49 CFR § 192.5(a) by using a "sliding mile."[14] When higher dwelling concentrations are encountered during the continuous sliding of this mile-long unit, the class location of the pipeline rises commensurately:

- Class 1: A unit along a continuous mile containing 10 or fewer buildings intended for human occupancy;
- Class 2: A unit along a continuous mile containing 11 to 45 buildings intended for human occupancy;
- Class 3: A unit along a continuous mile containing 46 or more buildings intended for human occupancy; and,
- Class 4: Exist where buildings with four or more stories above ground are prevalent.

Pipeline design factors are derating factors that ensure pipelines are operated below 100 percent of the maximum pipe yield strength.[15] Pipelines at higher class locations have lower pressures and MAOPs in order to increasingly protect people in areas with potentially higher consequences from an incident.

A class location change typically occurs when additional construction and development increases the density of structures in proximity to the pipeline above the current class's density threshold. If the pipeline's current MAOP is not commensurate with the new class location, existing regulations require that pipeline operators either:

- Reduce the pipe's MAOP to reduce stress levels in the pipe;

[13] ASME B31.8 is the current standard; the predecessor standard in place in 1970 was the USAS B31.8-1968: Gas Transmission and Distribution Ping Systems; USA Standard Code for Pressure Piping.

[14] The "sliding mile" is a unit that is 1 mile in length, extends 220 yards on either side of the centerline of a pipeline, and moves along the pipeline. The number of buildings within this sliding mile at any point during the mile's movement determines the class location for the entire mile of pipeline contained within the sliding mile. Class locations are not determined at any given point of a pipeline by counting the number of dwellings in static mile-long pipeline segments stacked end-to-end.

[15] Derating refers to the extent to which the pipeline operates below its maximum pipe yield strength. The formula in § 192.105 can be used to calculate the MAOP of a 1000 psig pipeline with the same operating parameters (diameter, wall thickness, yield strength, seam type, and temperature) but in different class locations (and therefore different design factors). The MAOP of that pipeline in the different class locations would be as follows: Class 1—design factor = 0.72; MAOP= 720 psig; Class 2—design factor = 0.60; MAOP= 600 psig; Class 3—design factor = 0.50; MAOP= 500 psig; Class 4—design factor = 0.40; MAOP= 400 psig.

- Replace the existing pipe with pipe that has thicker walls or higher yield strength to yield a lower operating stress at the same MAOP;
- Pressure test at a higher test pressure if the pipeline segment has not previously been tested at the higher pressure and for a minimum of 8 hours to confirm the MAOP; or,
- Apply for a Special Permit.

2.1 Special Permit Program

A nonemergency special permit, issued pursuant to 49 U.S.C. 60118(c)(1) and 49 CFR § 190.341, waives compliance with one or more pipeline safety regulatory requirements if PHMSA determines that granting the special permit would be consistent with pipeline safety. A class location special permit allows the pipeline operator to perform alternative conditions based on IMP principles and requirements in lieu of the regulations.

The class location special permits that PHMSA has granted have allowed operators to continue operating the pipeline segments identified under the special permits at the current MAOP based on the previous class locations. PHMSA developed its current class location special permit process by adapting IM concepts and published the typical considerations for class location change special permit requests initially in 2004.[16] In the 2004 Federal Register notice (69 FR 38948), PHMSA outlines certain requirements that pipelines must meet to be eligible for waiver consideration, including no bare pipe or pipe with wrinkle bends, records of a hydrostatic test to at least 1.25 times MAOP, records of ILI runs with no significant anomalies that would indicate systemic problems, and agreement that up to 25 miles of pipe both upstream and downstream of the waiver location must be included in the operator's IM program and periodically inspected using ILI technology. Further, the criteria provide no waivers for segments changing to Class 4 locations or for pipe changing to a Class 3 location that is operating above 72 percent SMYS.

Since 2004, PHMSA has granted 24 class location Special Permits, and based on its experience renewing some of the earliest class location change Special Permits, PHMSA has extended the expiration date of its class location change special permits from 5 years to 10 years.[17] For segments operating under a class location Special Permit, PHMSA typically requires operators to incorporate the affected segments into the company's O&M procedures and IM plan, perform additional assessments for threats identified during an operator's risk assessment, perform additional cathodic protection and corrosion-control measures, and repair any discovered anomalies on a specified schedule. See Exhibit 4-8 below for a list of class location change Special Permit conditions with potential costs.

The additional monitoring and maintenance requirements PHMSA prescribes through this process help to ensure the integrity of the pipe and protection of the population living near the pipeline segment at a comparable margin of safety and environmental protection throughout the life of the pipe relative to other compliance methods in the current regulations.

[16] 69 FR 38948 (June 29, 2004). Additional guidance is provided online at: *http://primis.phmsa.dot.gov/classloc/index.htm.* Public notices were published in the Federal Register. See 69 FR 22115 (April 23, 2004) and 69 FR 38948 (June 29, 2004); Docket No. RSPA–2004–17401—Pipeline Safety: Development of Class Location Change Waiver (Special Permit)
[17] PHMSA prepared an example Special Permit with typical conditions in 2012, which is available here: https://www.phmsa.dot.gov/pipeline/class-location-special-permits/example-class-location-special-permit-typical-condition. Also, see Appendix E for a list of the 24 Special Permits referenced here.

2.2 Proposed Rule Provisions

PHMSA is proposing to add a new compliance method for eligible Class 1 to Class 3 location changes. Please see Appendix A: Description of the Proposed Integrity Assessment Program for Class Location Changes for the details of proposed § 192.618.

This proposed new method is most similar to the existing Special Permit program, but does not replace Special Permit program. In effect, it would codify many conditions under which this option is available without the requirement of a special permit. Exhibit 2-1 summarizes the typical conditions in class location special permits that the proposed rule adopts in new § 192.618.[18] The proposed new method of compliance has six differences from Special Permit method. In comparison to Special Permit requirements, the new method would not require the following:

1. Reporting Pipe Coating and Remediation (#5),
2. Incorporate Damage Prevention Best Practices (#8),
3. Field Activity Notice to PHMSA (#9),
4. Annual Report to PHMSA (#11), and
5. Girth Weld Records (#15).

However, the new compliance method would require pipeline operators to have operational remote control of mainline valves, shown in Exhibit 2-1 under Remote Control or Automatic Shut-off Valves (#19). Not all operators with Special Permits are required to have operational remote controls on mainline valves on both sides of the special permit segment.

Exhibit 2-1: Comparison of Typical Special Permit Conditions and Proposed New Compliance Method Conditions, by Requirement

	Requirement	Typical Special Permit Condition	Proposed New Compliance Method Condition
1	Integrity Management Program	Yes	Yes
2	Close Interval Survey (Initial and Reassessment)	Yes	Yes
3	Coating Condition Survey (ACVG/DCVG)	Yes	No
4	Stress Corrosion Cracking Direct Assessment	Yes	Yes
5	Reporting Pipe Coating & Remediation	Yes	No
6	Amend O&M Manual	Yes	Yes
7	ILI Assessment and Reassessment	Yes	Yes
8	Incorporate Damage Prevention Best Practices	Yes	No
9	Field Activity Notice to PHMSA	Yes	No
10	Annual Report to PHMSA	Yes	No
11	Cathodic Protection Test Station Installation & Remediation	Yes	Yes
12	Interference Currents Control	Yes	Yes
13	Anomaly Evaluation and Repair	Yes	Yes
14	Girth Welds	Yes	No
15	Depth of Cover Survey	Yes	Yes
16	Line-of-Sight Markers	Yes	Yes

[18] https://primis.phmsa.dot.gov/classloc/docs/SpecialPermit_ExampleClassLocSP_Conditions_090112_draft1.pdf.

Exhibit 2-1: Comparison of Typical Special Permit Conditions and Proposed New Compliance Method Conditions, by Requirement

	Requirement	Typical Special Permit Condition	Proposed New Compliance Method Condition
17	Documentation & Records	Yes	Yes
18	Right-of-Way Patrols & Leakage Survey	Yes	Yes
19	Data Integration	Yes	Yes
20	Remote Control or Automatic Shut-off Valves	No	Yes

3 Regulatory Analysis Framework

3.1 Quantity of Class Location Change Activity

Gas transmission pipelines are divided into classes from 1 to 4 based on the number of buildings intended for human occupancy located in proximity to the pipeline. The proposed rule applies to pipeline segments changing from a C1 to C3 location, and therefore the proposed rule would affect current Class 1 pipelines, which comprise nearly 80 percent of all onshore transmission pipelines. Exhibit 3-1 summarizes the number of onshore gas transmission miles by their class location.

Exhibit 3-1: Onshore Gas Transmission Class Locations

Class Location	*Total Onshore Miles*	*Distribution by Class Location*
Class 1	232,768	78.2%
Class 2	30,315	10.2%
Class 3	33,539	11.3%
Class 4	932	0.3%
Total	297,554	100%

Source: PHMSA 2017 Annual Report, Parts L & Q

PHMSA is proposing that in order for a pipe segment to be eligible for the new rule option, the C1 to C3 location segment change must occur after the effective date of rule. The regulatory analysis therefore requires an estimate of current class location change activity specifically for prospective C1 to C3 changes. Below, PHMSA summarizes its analysis for estimating the baseline quantity of miles changing from C1 to C3 on an annual basis based on data obtained from surveys of operators performed by industry associations, which are validated by historical data in the 2017 Annual Report, Part L and Part Q.

Four prominent trade associations representing pipeline operators and related industries surveyed their members about information relevant to class change including total annual pipeline replacements due to class change from 2011 to 2017 and those expected in the future. The associations provided this information in public comments. The respondents to the survey represented 160,000 miles of transmission pipeline, more than half of the total size of the system in the United States. Exhibit 3-2 tabulates the pipeline replacement mileage data from the survey, the total size of the transmission pipeline system, and the estimated pipeline replacement mileages.[19] The pipeline replacement estimate assumes pipeline operators that did not respond to the survey replace pipelines at the same rate as responsive operators. PHMSA believes this is a reasonable assumption given that the survey's respondents captured approximately half of all onshore transmission pipeline miles (160,000 miles).

Scenario 1 is based on the baseline estimate of pipeline replacement due to class change of 66.8 miles per year. This value is the average of annual pipeline replacements from 2011 to 2017 estimated from public comments and implies a total class change of 77.6 miles per year after accounting for the other methods of accommodating for class change (i.e. special permits, MAOP reduction, and pressure test). Scenario 2 is based on a baseline pipeline replacement rate of 105.6 miles per year estimated from the projection provided in the same public comments. This value for Scenario 2 implies a total class change of 117.6 miles after including the other methods of accommodating class change. Based on an

[19] See Table 2 of Comments filed by American Gas Association, American Petroleum Institute, American Public Gas Association, and Interstate Natural Gas Association of America, October 1, 2018, Docket No. PHMSA-2017-0151.

average segment length of approximately 0.26 miles, and assuming one excavation per segment, PHMSA estimates between 257 and 406 excavations in the baseline. As described below in Section 4.1.1, for Class 1 to Class 3 change managed by Special Permit, PHMSA assumed the historical average of 8.4 miles per year would hold for the baseline. PHMSA also assumed that 1.5 percent of Class 1 to Class 3 change would be accommodated by MAOP reduction and 1.5 percent by pressure testing. Thus, the pipeline replacement estimate is added to the Special Permit estimate and then this sum is scaled up by a factor of 1/(1-0.015-0.015) to estimate the total quantity of class location miles for all compliance methods.

Exhibit 3-2: Industry Reported Pipeline Replacement due to Class Change and Estimated Totals

	2011	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*Average*	*Projection*
Survey Replacement Mileage	43	36	51	38	39	10	34	38.5	57.0
Transmission Mileage	299,778	298,594	298,383	297,883	297,256	296,598	297,554		
Estimated Total Replacement Mileage	81	67	95	71	72	19	63	66.8	105.6
Implied Total Class 1 to Class 3 Change Mileage								**77.6**	**117.6**

Source: PHMSA analysis of data provided by industry and 2011-2017 Annual Report data

To validate the estimates provided by industry, PHMSA analyzed historical Annual Report data. This analysis is detailed in Appendix B: Estimating the Annual Quantity of Miles Changing from Class 1 to Class 3, and indicates estimation bounds of 39.5 to 354.9 miles per year for the average change from C1 to C3. The resulting range, particularly the upper bound, is a byproduct of the annual report data limiting PHMSA's ability to clearly discern C1 to C3 changes from other changes. Specifically, the upper-bound estimate captures instances when miles move out of Class 1 from one year to the next, but changes in other classes obscure any indication of whether any Class 1 miles moved to Class 3 (see Appendix B). The scenarios based on industry comments of 77.6 and 117.6 miles per year are well within the bounds estimated by this analysis.

Exhibit 3-3: Estimates of Historical Class 1 to Class 3 Changes for Gas Transmission (miles)

	2011	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*Average*
Lower Bound	21	57	57	55	40	11	35	**39.5**
Upper Bound	330	400	711	460	152	168	264	**354.9**
Overall Average								197
Overall Median								104

Source: PHMSA analysis based on Annual Report Part L data

3.2 Baseline Case

The baseline case for this regulatory analysis represents PHMSA's best assessment of conditions absent the regulatory action, and accounts for the practices and standards implemented by pipeline operators under existing regulations. On October 1, 2019, PHMSA issued a final rule titled, "Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," which expands IM assessment requirements to include pipelines in newly defined ''Moderate Consequence Areas'' (MCA).[20] Operators of pipelines in MCAs are similarly required to perform a subset of activities that mitigate, to some degree, part of the costs of complying with class change requirements under the Special Permit Program. The PRIA for this proposed rule accounts for HCA and MCA actions that overlap with the Special Permit and proposed rule methods of compliance. Other key inputs, that are used to establish the baselines case and to analyze the impacts due to the proposed rule case include:

- The quantity of miles changing from C1 to C3 annually: 77.6 miles in Scenario 1 or 117.6 miles in Scenario 2 based on information provided by pipeline operators. These annual increases are consistent with PHMSA estimates based on annual report data (see Appendix B).
- The utilization rate of currently available compliance methods, described in Section 4.1. PHMSA estimates that segments undergoing a C1 to C3 location change in the baseline will be managed primarily through pipe replacement (86 to 90 percent utilization), with 7 to 11 percent of baseline changes using the existing Special Permit program and 3 percent using the pressure test or derating options, where the new class MAOP is acceptable to the operator.
- The unit costs of compliance for the Special Permit program and for pipe replacement are described in Section 4.2.
- The mix of consequence classifications among affected segments (i.e. HCA, MCA, non-HCA/MCA), which informs the assignment of costs associated with using the Special Permit program in the baseline. Baseline costs incurred by operators managing class changes can vary based on a given segment's consequence area. As described in Section 4.3, some of the compliance requirements under the Special Permit program are already performed for HCA-classified segments. Therefore, baseline Special Permit program costs are lower for HCA segments compared to non-HCA segments.

3.3 Proposed Rule Case

The proposed rule case is based on the same set of key assumptions as the baseline, but adds a new compliance method that redistributes the utilization rates among the three methods (pipe replacement, special permit and the new compliance method). The new compliance method assumes that all affected segments in the future will use this option if they qualify. This is in contrast to the baseline, where the choice of compliance methods reflects their historical rate of utilization.

As described in Section 4.1, PHMSA estimates that most of the segments managed using the Special Permit method in the baseline would switch to the new compliance method, and they achieve regulatory relief and cost savings by avoiding the Special Permit application and renewal process. Similarly, most of the segments managed using pipe replacement in the baseline are estimated to switch to the new, proposed rule compliance method. Pipeline companies operating these segments

[20] 84 FR 52180.

achieve regulatory relief and cost savings due to the lower cost of implementing a class change through the rule option, compared to pipe replacement.

3.4 Other PRIA Assumptions

3.4.1. Timeframe for the Analysis

PHMSA estimates costs and benefits over the 20-year period of 2020–2039, which provides a sufficient duration to account for and capture the important impacts of the proposed rule, but not longer than necessary given the additional uncertainty in even longer-term estimates. The service lives of replaced pipelines that qualify for the new method of compliance proposed in the NPRM are expected to extend well beyond this 20-year period of analysis. Pipelines managed under the new method may not degrade to the point of requiring replacement before the pipeline is decommission or otherwise replaced due to market changes and other changes in the distant future. Replacement in the distant future (beyond 20 years) cannot accurately be estimated and, because of discounting, the present value of the estimated costs of the replacement will be relatively small compared to other costs in the analysis. Thus, PHMSA expects the conclusions of this analysis will be unaffected by distant future costs that might be incurred if the unreplaced pipeline managed under the compliance method introduced in the NPRM needs to be replaced.

3.4.2. Discounting of Future Costs and Benefits

The analytic framework includes two basic temporal components, which are used consistently throughout the analysis of costs and benefits:

- **Use of constant prices**. This analysis applies a year 2018 constant price level to all future costs and benefits. Some monetary values of benefits and costs are based on historical market prices, and in those instances, PHMSA updated the prices to 2018 by multiplying them by appropriate indexes based on the type of cost.
- **Discount rate and year**. The analysis discounts all costs to 2020 present value terms. Present value and annualized costs are estimated using discount rates of 3 percent and 7 percent, consistent with guidance provided by the Office of Management and Budget (OMB) in Circular A-4.

3.4.3. Regulatory Alternatives

PHMSA analyzed the proposed rule with respect to the projected baseline assuming no changed to existing class location rules. The PRIA defines the baseline as the “No Action” alternative and analyzes the “Proposed Option” relative to the baseline. In the proposed rule PHMSA amends the class location regulations for some in-service gas transmission segments where the class location changes from a Class 1 to a Class 3 to include an IM option and other defined pipeline safety measures is appropriate and in the interest of pipeline safety.

4 Analysis of Costs and Cost Savings

PHMSA's cost analysis for the proposed rule begins with the baseline estimate of C1 to C3 change activity –as described in Section 3.1 – and includes three principal steps:

1. **Estimate the compliance methods to manage class location changes (Section 4.1) –** PHMSA distributes the quantity of annually affected pipeline miles across the set of available compliance methods for the baseline and proposed rule. The utilization of different compliance methods varies between the baseline and proposed rule.
2. **Estimate unit costs for class location changes compliance methods (Section 4.2)** – Next, PHMSA develops unit-level cost estimates for each compliance method included in the baseline and proposed rule (e.g., cost per mile for pipe replacement).
3. **Estimate total costs for affected class location changes (Section 4.3) –** PHMSA then assigns applicable unit costs to pipeline mileage using each compliance method in order to estimate the proposed rule's total annual costs.

4.1 Utilization Rates for Class Location Change Compliance Methods

4.1.1. Baseline

In the baseline, the current regulations allow operators to choose from four methods to confirm or revise their MAOP of their transmission pipeline when the class location changes from a C1 to C3 location:

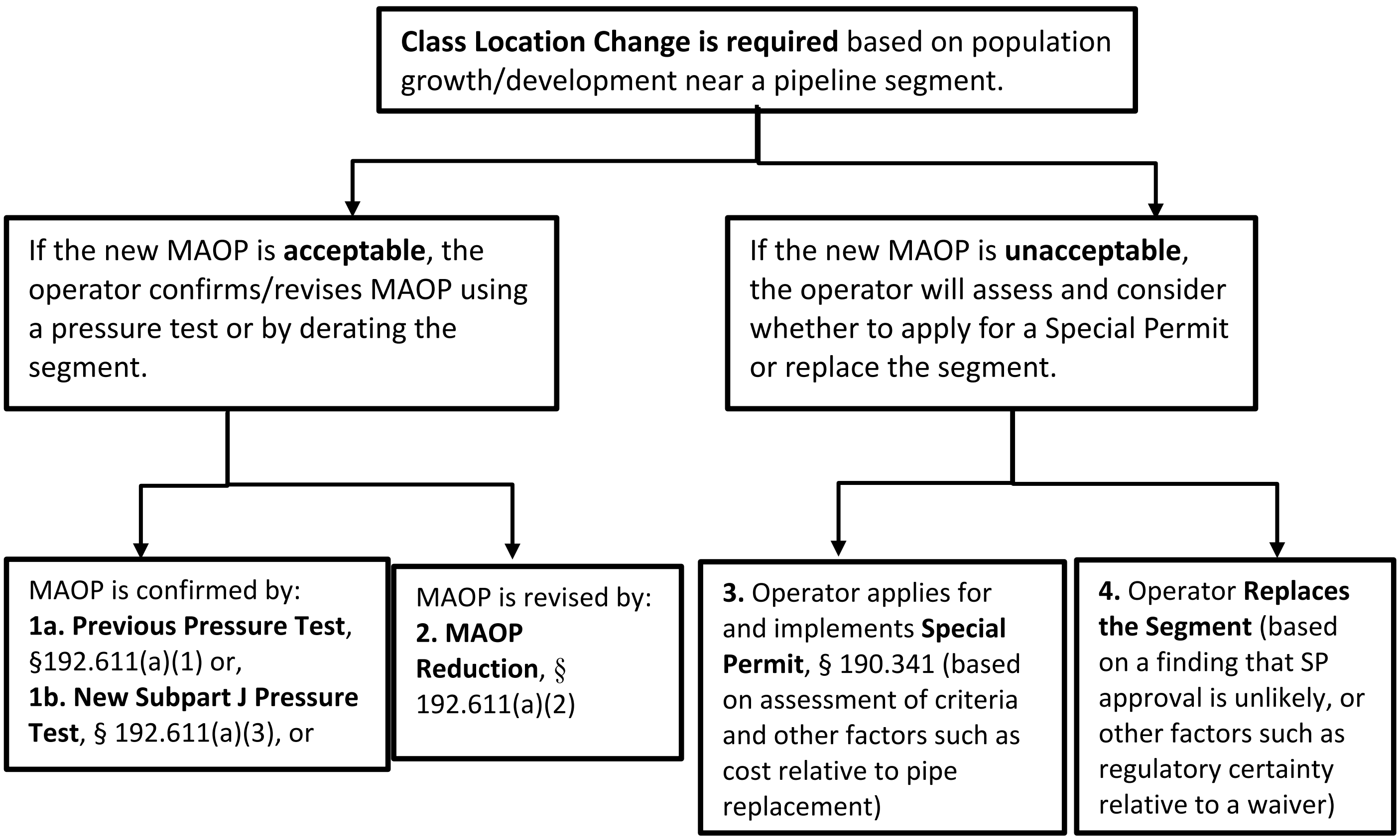
1. **Pressure Test**.
    a. Under § 192.611(a)(1), if the segment involved has been previously tested in place for a period of not less than 8 hours and the MAOP (and alternative MAOP) is 0.667 times the test pressure in Class 3 locations, and the corresponding hoop stress does not exceed 60 percent of SMYS in Class 3 locations; or
    b. Under § 192.611(a)(3), the segment involved must be tested in accordance with the applicable requirements of subpart J of this part, and its MAOP must then be established according to the same criteria under §192.611(a)(1);
2. **MAOP Reduction.** Under § 192.611(a)(2), the MAOP 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. **Special Permit.** Under § 190.341, the operator applies for regulatory relief in the baseline scenario to waive the requirements of the CFR for pipeline segments where the class location of the segment has been changed; or
4. **Pipe Replacement.** The operator replaces a Class 1 pipe segment with pipe that meets the MAOP/design requirements for Class 3 areas.

Exhibit 4-1 illustrates how a pipeline operator might consider these options. As population around a pipeline increases and the pipeline's class location increases, the numeric value of the design factor decreases, which translates, via the formula at § 192.105, into a lower MAOP for a pipeline segment. The new MAOP may be acceptable to the operators if the segment is essentially already operating at a sufficiently low pressure, demonstrated by previous or new pressure testing (i.e., option 1a or 1b).

Similarly, but perhaps less likely, the new MAOP may be essentially acceptable if conditions allow the operator to reduce pressure in the segment without an adverse business or operations outcome. To the extent either of these options is preferred by the operator, the addition of the proposed rule option would not alter the compliance decision (i.e. if the operator would not use replacement or the special permit in the baseline, they would similarly not use the proposed rule option, once introduced).

Absent conditions in which an operator prefers either of these options, the operator can evaluate whether to pursue a special permit waiver or pipe replacement. Referring to Exhibit 4-1, the proposed rule option effectively codifies the special permit (#3), with some modifications. The proposed rule method becomes a substitute for the special permit and pipe replacement with respect to baseline class location changes.

Exhibit 4-1: Class Location Change Compliance Methods



Pressure Test and MAOP Reduction (Options 1a, 1b, and 2)

Operators who find the new MAOP for their segment acceptable may use the pressure test or derating option. PHMSA believes that the vast majority of segments undergoing future C1 to C3 location changes will find the new MAOP unacceptable, and therefore assumes that only a small proportion of baseline changes are managed using these methods: 1.5 percent each, or 3 percent in total between these options. This assumption is based in part on the substantial increase in the safety factor required for this two-class change, which could negatively affect an operator's ability to deliver required volumes. In addition, PHMSA received comments in response to the ANPRM consistent with the general assumption. For example, the American Gas Association (AGA) indicated that the current pressure-test options and customer impacts of pressure reductions often result in pipe replacement as the only practicable option allowed by current regulations to manage a class location change, particularly when a segment has experienced a C1 to C3 change.[21]

Special Permit (Option 3)

The purpose of this section is to estimate the historical C1 to C3 change that was managed using the Special Permit option. PHMSA assumes that the historical average of 8.4 miles per year of C1 to C3 location change managed using the Special Permit compliance method will continue as the annual total for the baseline.

The data below in Exhibit 4-2 indicate approximately 59 miles managed C1 to C3 changes using the Special Permit program over the same time period. To estimate this value, PHMSA relied on public data submitted during 2016 by four operators applying for Special Permits for over 260 segments of pipe covering 63.4 miles.[22] From 2010 to 2017, PHMSA granted four new special permit application requesting regulatory relief from § 192.611.[23] Of the 260 segments, 238 were in relation to C1 to C3 changes, or 59 miles. Thus, the use of the Special Permit option averaged 8.4 miles per year from 2010 to 2017.

Exhibit 4-2: Summary of Historical Special Permit Class Location Change Data

Class Upgrade	*No. of Segments*	*Miles*	*Miles per Segment*
1 to 2	11	2	0.18
1 to 3	**238**	**59**	**0.25**
2 to 3	11	2	0.21
Total	260	63	0.24

Source: See Footnote 22

Pipe Replacement (Option 4)

As described in Section 3.1, two pipe replacement scenarios were used in the two baseline scenarios. These scenarios are based on public comments provided by the pipeline industry.

4.1.2. Proposed Rule

PHMSA assumes that all prospective C1 to C3 changes will use the proposed rule option if they qualify (i.e. that the proposed rule option is preferred to both pipe replacement and the current Special Permit program). This will cause some operators to switch from their baseline compliance approach, either replacement or Special Permit, to the proposed rule option.

Switching from Special Permit to the Proposed Rule Method

Based on the same historical Special Permit data described above, PHMSA estimates that approximately 72 percent of the miles managed via Special Permit in the baseline would qualify for the proposed rule option with respect to the material properties and other characteristics required under the

[21] AGA, API, APGA & INGAA, "Comments On Pipeline Safety: Class Location Change Requirements," at 9 (October 1, 2018).
[22] This data can be accessed at regulations.gov in dockets: Tennessee Gas Pipeline Company (Docket No. PHMSA-2016-0004), Southern Natural Gas Company (Docket No. PHMSA-2016-0006), El Paso Natural Gas Company (Docket No. PHMSA-2016-0007), Colorado Interstate Gas Company (Docket No. PHMSA-2016-0008).
[23] PHMSA has rejected class location change special permits due to the presence of pipe conditions (including cracking, major corrosion, or other systemic issues) that are not easy to address via the special permit process. PHMSA considers the age and manufacturing process of the pipe and the construction processes used as well when issuing special permits. Additionally, some operators have withdrawn special permit applications before having their applications formally denied by PHMSA.

new § 192.618(e). Operators switching from the Special Permit program in the baseline to the rule option achieve regulatory relief primarily from the absence of the Special Permit application and renewal process.

Switching from Pipe Replacement to the Proposed Rule Method

With respect to the population of baseline replacements (86 to 90 percent of total affected baseline miles), the historical Special Permit application data do not provide insight to characterize the proportion that would switch from replacement to the rule option. But using a similar approach relying on Annual Report data (Parts K, D, R, and Q), PHMSA estimates the proportion of all Class 1 miles – prospective future class changes – that meet specific screening criteria indicative of the ability to use the proposed rule option (per criteria in Appendix A: Description of the Proposed Integrity Assessment Program for Class Location Changes). Based on these data, PHMSA estimates that 34 percent of miles managed via replacement in the baseline will switch to the proposed rule option. See Appendix C for additional details. The segments that switch from replacement in the baseline to the proposed rule option would, conceptually, include segments that qualified for the special permit in the baseline but elected not to use that option. This could be due to a variety of factors, such as: 1) the uncertainty and burden associated with managing a recurring special permit, 2) the pipeline needed to be replaced for reasons independent of the class location change, or 3) other operator- and segment-specific business considerations.

4.1.3. Summary of Mileage by Compliance Method: Baseline vs. Proposed Rule

Exhibit 4-3 and Exhibit 4-4 present the utilization rates of compliance methods for C1 to C3 location changes in the baseline and proposed rule.

Approximately 23 to 42 miles per year are estimated to switch to the proposed rule option depending on the activity Scenario. This value is comprised mostly of miles switching from pipe replacement in the baseline to the proposed rule method, along with a small number of miles per year switching from the Special Permit baseline method to the proposed rule method.

Exhibit 4-3: Scenario 1 Compliance Utilization Rates and Mileage for C1 to C3 Changes: Baseline and Proposed Rule

	Baseline		*Proposed Rule*		
Compliance Method	**Compliance Utilization Rate**	**Annual C1 to C3 Miles**	**Compliance Utilization Rate**	**Annual C1 to C3 Miles**	**Change from Baseline (miles)**
Pressure Test	1.5%	1.2	1.5%	1.2	0
MAOP Reduction	1.5%	1.2	1.5%	1.2	0
Special Permit Waiver	10.9%	8.4	3.0%	2.3	-6.1
Pipe Replacement	86.1%	66.8	56.6%	43.9	-22.9
New Compliance Method	0%	0	37.4%	29.0	29.0
Total	**100%**	**77.6**	**100%**	**77.6**	**0**

Exhibit 4-4: Scenario 2 Compliance Utilization Rates and Affected Mileage for C1 to C3 Changes: Baseline and Proposed Rule

	Baseline		*Proposed Rule*		
Compliance Method	**Utilization Rate**	**Annual C1 to C3 Miles**	**Utilization Rate**	**Annual C1 to C3 Miles**	**Change from Baseline (miles)**
Pressure Test	1.5%	1.8	1.5%	1.8	0

MAOP Reduction	1.5%	1.8	1.5%	1.8	0
Special Permit Waiver	7.2%	8.4	2.0%	2.3	-6.1
Pipe Replacement	89.8%	105.6	59.0%	69.4	-36.2
New Proposed Compliance Method	0%	0	36.0%	42.3	42.3
Total	**100%**	**117.6**	**100%**	**117.6**	**0**

4.2 Unit Costs for Class Location Change Compliance Methods

This section describes the unit costs of compliance associated with class location change compliance methods. Unit costs for pipe replacement, the Special Permit process, and the new proposed rule method are normalized on a dollars-per-foot basis in most instances (or another normalizing basis as appropriate, such as dollars-per-repair). Costs are estimated for the individual requirements that comprise the Special Permit and proposed rule methods.

4.2.1. Pressure Test or MAOP Reduction

The analysis assumes that three percent of the future changes will utilize either pressure test option, or the derating option. This assumption is based in part of the substantial increase in the safety factor required for this two-class change, which could negatively affect an operator's ability to deliver required volumes. In addition, PHMSA received comments in response to the ANPRM consistent with the general assumption. For example, AGA indicated that the current pressure-test options and customer impacts of pressure reductions often result in pipe replacement as the only practicable option allowed by current regulations to manage a class location change, particularly when a segment has experienced a C1 to C3 change.[24] PHMSA notes that to the extent operator(s) do elect either of these approaches for future class location changes, it is presumed that selection is preferred to any of the other options, and that the proposed rule would not have any direct effects on these segments.

4.2.2. Special Permit Program and the Proposed Rule Option (§ 192.618(e))

PHMSA presents unit costs for the Special Permit method and new compliance method together because many of their requirements and cost elements overlap and are nearly identical.

PHMSA outlined "threshold conditions" pipelines must meet to be considered for a special permit after a class location change in a 2004 notice.[25] The proposed rule method in § 192.618(e)) incorporates most of these requirements. The new compliance method also would require pipeline operators to have operational remote control of mainline valves, which is not a requirement under the Special Permit program.

Exhibit 4-5 compares the requirements for both methods, along with PHMSA's unit cost estimates. These are the unit costs for the special permit and the proposed rule option; the unit cost-per-foot (cost-per-mile) for replacement is presented in the next section, 4.2.3. Appendix D includes PHMSA's detailed methodology for estimating the unit costs of each requirement.

[24] AGA, API, APGA & INGAA, "Comments On Pipeline Safety: Class Location Change Requirements" at 9.
[25] 69 FR 38948.

Exhibit 4-5: Special Permit vs. Proposed Rule Method

Condition	Brief Condition Description	Special Permit Condition	New 192.618 Requirement	One-time or Recurring Activity	Requirement Cost ($/foot unless otherwise noted)
Integrity Management Program	Operator must incorporate the segments into its integrity management program in a high consequence area.	Yes	Yes	One-Time	$0.57
Coating Condition Survey (ACVG/DCVG)	Operator must perform a Direct Current Voltage Gradient (DCVG) survey or an Alternating Current Voltage Gradient (ACVG) survey of each segment to determine the pipeline coating conditions and must then remediate any integrity issues.	Yes	No	One-Time	$1.06
Stress Corrosion Cracking Direct Assessment	Operator must evaluate the pipeline name pipelines for stress corrosion cracking.	Yes	Yes	One-Time	$8.10
Reporting Pipe Coating & Remediation	Operator must submit the DCVG or ACVG, CIS, and SCCDA findings including remediation actions in a written report to PHMSA.	Yes	No	One-Time	$0.11
Amend O&M Manual	Operator must amend applicable sections of its operations and maintenance (O&M) manual(s) to incorporate the inspection and reassessment intervals. PHMSA assumes 80 hours of labor for this activity – see Appendix D.	Yes	Yes	One-Time	$4.57
Incorporate Damage Prevention Best Practices	Operator must incorporate the applicable best practices of the Common Ground Alliance	Yes	No	One-Time	$0.11
Field Activity Notice to PHMSA	Operator must give a minimum of 14 days advance notice to PHMSA to observe the certain excavations.	Yes	No	One-Time	$0.57
Cathodic Protection Test Station Installation & Remediation	At least one cathodic protection pipe-to-soil test station must be located within one-half mile of each segment and if any annual test station readings fall below 49 CFR part 192, subpart I requirements, remediation must occur.[26]	Yes	Yes	One-Time	$5,500 per segment
Anomaly Evaluation and Repair	Operator must account for ILI tool tolerance and corrosion growth rates in scheduled response times and repairs and document and justify the values used. In addition to implementing the evaluation, repair, and remediation scheduling requirements in § 192.933 to address anomalous conditions, an operator must comply with the additional repair criteria.	Yes	Yes	One-Time	$584,340 per repair
Girth Weld Records	Operator must provide records to PHMSA to demonstrate the girth welds on the pipeline segment were non-destructively tested at the time of construction.	Yes	No	One-Time	$0.29
Depth of Cover Survey	Operator must complete a depth of cover survey.	Yes	Yes	One-Time	$1.37

[26] PHMSA assumes one station per segment, given the half-mile spacing requirement, and PHMSA's data which indicate the average segment changing from C1 to C3 is about 0.26 miles. Based on PHMSA's analysis of 260 segments of C1 to C3 special permits, only 10% were greater than 0.5 miles, and the largest segment was 0.86 miles. Although direct information is not available, cases where segments are long enough to require multiple test stations are plausibly balanced by cases with nearby short segments that can share a station, so that one station per segment is an appropriate estimate.

Condition	Brief Condition Description	Special Permit Condition	New 192.618 Requirement	One-time or Recurring Activity	Requirement Cost ($/foot unless otherwise noted)
Line-of-Sight Markers & Pipe Warning Tape	The operator must install and maintain line-of-sight markings by the segments and must install pipeline warning tape in all integrity excavations.	Yes	Yes	One-Time	$2.34
Documentation & Records	The operator must maintain the following records for each segment.	Yes	Yes	One-Time	$0.34
Data Integration	Operator must maintain and integrate data collection on pipe segment conditions.	Yes	Yes	One-Time	$25.14 per segment
Remote Control or Automatic Shut-off Valves	Mainline valves on both sides of the segment may not exceed 20 miles apart, must be operational remote-controlled valves or automatic shutoff valves with pressure sensors on each side of the mainline valves	No	Yes	One-Time	$44,500 per valve
PHMSA Staff Support	PHMSA prepares NEPA analyses and reviews Special Permit Applications.	Yes	No	One-Time	$7.00
Interference Currents Control	The operator must address induced alternating current (AC) from parallel electric transmission lines and other interference issues such as direct current (DC) in the segment inspection areas that may affect the pipeline.	Yes	Yes	Recurring for Special Permit One-Time for Rule	$0.96
Close Interval Survey (Initial & Reassessment)	Operator must perform a close interval survey along the entire length of the segment and remediate any areas of inadequate cathodic protection. Operator must perform a periodic CIS of the segments at the applicable reassessment interval(s).	Yes	Yes	Recurring	$0.86
ILI Assessment and Reassessment	Operator must perform ILI assessment and reassess along the entire length of the segment area using both high resolution magnetic flux leakage (HR-MFL) and either HR-geometry or HR-deformation tools according to § 192.939.	Yes	Yes	Recurring	$0.86
Annual Report to PHMSA	Operator must provide annual reports to PHMSA on a variety of project topics.	Yes	No	Recurring	$6.95
Right-of-Way Patrols & Leakage Surveys	Operator must perform ground or aerial and ground right-of-way patrols.	Yes	Yes	Recurring	$0.89

4.2.3. Pipe Replacement

Pipe replacement is often the only practicable choice for operators to comply with current regulations for Class 1 designed pipes operating in a Class 3 location. Below, PHMSA presents pipeline replacement costs for the design, materials, inspection, and installation of a designated length of pipe within an 8-mile segment, with mainline valves on each end of the segment. Exhibit 4-6 shows the costs presented by segment length and pipe diameter. Exhibit 4-6 converts these costs to a weighted average cost of $585 per foot based on the average cost for each segment weighted by the proportion of all onshore pipes in each diameter category.

Exhibit 4-6: Pipeline Replacement Costs ($2018 per foot)

Diameter (inches)	*1,000-ft. Segment*	*2,000-ft. Segment*	*3,0000-ft. Segment*	*4,000-ft. Segment*	*5,000-ft. Segment*	*Segment Length Average Cost*	*Percent of All Pipes, by Diameter*
10	$394	$295	$262	$245	$235	$286	31%
16	$534	$413	$373	$352	$340	$402	22%
24	$723	$588	$543	$520	$507	$576	16%
36	$1,176	$1,012	$957	$930	$913	$998	27%
42	$1,435	$1,260	$1,202	$1,173	$1,156	$1,245	4%
Weighted Average Pipe Replacement Cost						$585.5	
Cost per Mile[27]						$3,091,255	

Source: Gulf Interstate Engineering 2017 and PHMSA 2017 Annual Report.

4.2.4. Summary of Unit Costs per Mile

Exhibit 4-7 summarizes per-mile compliance costs for the special permit and proposed rule, by consequence area type. This summary sorts the cost components described in Table 4-4 into one-time and recurring costs and sums the costs that apply to pipelines in the three different consequence area designations. The costs are lower for the more sensitive consequence areas because some of the special permit and proposed rule requirements are already required for pipeline in those consequence areas. As shown in Exhibit 4-6, the pipe replacement option has a one-time cost of $3,091,255 per mile. The proposed rule option is more expensive than the special permit option in terms of up-front costs, but is less expensive in terms of recurring cost over the long-run. This table also illustrates how costs increase for MCAs and non-HCA/MCA segments, compared to HCA segments.

Exhibit 4-7: One-Time and Recurring Compliance Costs, per-Mile, by Compliance Option

Compliance Option	**Consequence Area Designation**		
	HCA	**MCA**	**Non-HCA/MCA**
Special Permit Compliance Option			
One-time costs	$65,474	$108,592	$318,594
Recurring costs	$93,063	$93,063	$95,086
Total costs (year 1)	**$158,538**	**$201,655**	**$413,680**
Proposed Rule Compliance Option			
One-time costs	$229,285	$272,403	$275,416
Recurring costs	$56,373	$56,373	$57,672
Total costs (year 1)	**$285,658**	**$328,776**	**$333,089**

4.3 Total Costs for Class Location Change Compliance Methods

This section describes PHMSA's analysis of total costs, which requires assigning incremental costs, by compliance method, to the quantity of miles using each compliance method, on an annual basis. When

[27] Cost per Mile = Weighted Average Pipe Replacement Cost x 5,280 feet/mile.

assigning costs to miles managed via the Special Permit and new proposed rule method, it is important to account for how incremental requirements can vary for HCA, MCA, and non-HCA/MCA segments.

4.3.1. Affected Mileage by Consequence Area

As indicated in Exhibit 4-7 (and described in Section 4.2 and Appendix D) incremental costs incurred by operators managing class changes can vary based on a given segment's consequence area designation (i.e., HCA, MCA, non-HCA). Some of the requirements and unit costs, for both the Special Permit and proposed rule method for managing class changes, are not incremental or new. For example, ILI is already required of pipe operating in HCA or MCA locations, and therefore, PHMSA assumes this pipe is already included in operator IMPs. It is important to note that this differentiation in applicable requirements and costs by consequence area applies to both the baseline scenario (i.e. for miles using the Special Permit) and the proposed rule scenario (i.e. for miles using either the Special Permit or the new proposed rule method, per Exhibit 4-8).

Exhibit 4-8: Summary of Incremental Requirements by Consequence Area

Compliance Method	Consequence Location		
	HCA	MCA	Non-HCA and Non-MCA
Special Permit Conditions			
Condition 2: IMP Requirements			✓
Condition 3 & 4: CIS Survey (Initial and Reassessment)			✓
Condition 5: Coating Condition Survey (ACVG/DCVG) & Condition 22: Casings			✓
Condition 6: SCC DA			✓
Condition 7: Reporting Pipe Coating & Remediation	✓	✓	✓
Condition 8 & 9: Amend O&M Manual			✓
Condition 10 & 11: ILI Assessment and Reassessment			✓
Condition 12: Incorporate Damage prevention BP			✓
Condition 13: Field Activity Notice to PHMSA	✓	✓	✓
Condition 15: AR to PHMSA	✓	✓	✓
Condition 16 & 17: Cathodic Protection Test Station	✓	✓	✓
Condition 18: Interference Currents Control			✓
Condition 20: Anomaly Evaluation and Repair		✓	✓
Condition 21: Girth Welds	✓	✓	✓
Condition 24: Specific Conditions: DoC Survey, Markers,	✓	✓	✓
Condition 24: Right-of-way Patrols	✓	✓	✓
Condition 24(e) & 25: Documentation & Data Integration			✓
PHMSA Staff Support	✓	✓	✓
Proposed Rule Option § 192.618(e)			
(a)IMP Requirements			✓
(a) (2) ILI Initial Assessment & Reassessment			✓
Remediation Schedule & Pipe and Weld Cracking Inspections		✓	✓
Close Interval Survey			✓
Cathodic Protection Test Station	✓	✓	✓
Line of Sight Markings	✓	✓	✓
Interference Survey & Depth of Cover	✓	✓	✓
(Right of Way Patrol and Leakage Surveys			✓
Remote Control or Automatic Shut-Off Valves	✓	✓	✓
Documentation	✓	✓	✓

To account for differences in the cost of compliance methods in different consequence areas, PHMSA first estimates the distribution across consequence areas for miles managing class changes with each compliance method. The purpose of this step is to disaggregate the quantity of miles managed using each compliance method (total miles using each method is presented previously in Exhibit 4-3 and Exhibit 4-4 for Scenario 1 and Scenario 2 by consequence area: HCA, MCA, non-HCA/MCA.

- **Miles managed using the Special Permit in the baseline and miles that switch from the Special Permit to the Proposed Rule method** – Annual C1 to C3 changes are disaggregated based on the mix of consequence areas present in the historical special permit application data, for segments that would qualify for the proposed rule method, described in Appendix C and Exhibit C-1: *18% HCA, 49% MCA, 34% non-HCA/MCA*;
- **Miles that switch from Pipe Replacement in the baseline to the Proposed Rule method** – Annual C1 to C3 changes are disaggregated based on the mix of consequence areas for all onshore Class 1 transmission pipelines: *1% HCA, 5% MCA, 94% non-HCA/MCA.* PHMSA estimates the proportion of HCA miles in Class based on the data presented in Exhibit 3-1, and the proportion of MCA miles based on the data described in Section 4.1.2 (11,860 miles). Remaining Class 1 miles are make up the additional 94 percent; and,
- **Miles managed using Pipe Replacement –** Costs for annual C1 to C3 changes do not vary by consequence area, and therefore, mileage managed using this approach is not disaggregated by consequence area.

Exhibit 4-9 and Exhibit 4-10 present PHMSA's resulting disaggregated estimates of the quantity of miles managing C1 to C3 changes, annually, by compliance approach and consequence area (this is a disaggregated version of Exhibit 4-4).

Exhibit 4-9: Scenario 1 Annual Affected Mileage by Consequence Area and Compliance Approach

Compliance Approach	*Number of Miles Changing from Class 1 to Class 3, annually*		
	Baseline Scenario	*Rule Scenario*	*Change Due to Rule*
Pressure Test	**1.2**	**1.2**	**0**
MAOP Reduction	**1.2**	**1.2**	**0**
Special Permit	**8.4**	**2.3**	**-6.1**
HCA	1.5	0.4	-1.1
MCA	4.1	1.1	-3.0
Non-HCA/MCA	2.9	0.8	-2.1
Pipe Replacement	**66.8**	**43.9**	**-22.9**
Proposed Rule Option	**0.0**	**29.0**	**29.0**
HCA	**0.0**	1.2	1.2
MCA	**0.0**	4.1	4.1
Non-HCA/MCA	**0.0**	23.7	23.7
Total Miles per Year	**77.6**	**77.6**	**0.0**

Exhibit 4-10: Scenario 2 Annual Affected Mileage by Consequence Area and Compliance Approach

Compliance Approach	*Number of Miles Changing from Class 1 to Class 3, annually*		
	Baseline Scenario	*Rule Scenario*	*Change Due to Rule*
Pressure Test	**1.8**	**1.8**	**0.0**
MAOP Reduction	**1.8**	**1.8**	**0.0**
Special Permit	**8.4**	**2.3**	**-6.1**
HCA	1.5	0.4	-1.1
MCA	4.1	1.1	-3.0
Non-HCA/MCA	2.9	0.8	-2.1
Pipe Replacement	**105.6**	**69.4**	**-36.2**
Proposed Rule Option	**0.0**	**42.3**	**42.3**
HCA	0.0	1.3	1.3
MCA	0.0	4.8	4.8
Non-HCA/MCA	0.0	36.2	36.2
Total Miles per Year	**117.6**	**117.6**	**0.0**

4.3.2. Total Costs

Annual costs for all compliance methods are analyzed for 20 years, from 2020 – 2039. In each year of the analysis, 77.6 or 117.6 miles of pipeline change from C1 to C3, per the activity baseline. For the set of miles changing in any given year, those segments (miles of pipeline) may be subject to the following types of costs:

- One-time costs, which are modeled as occurring in the year that a given set of pipeline segment miles changes class locations. For example, pipelines changing from C1 to C3 in 2023 incur any one-time costs in 2023.
- Annually recurring costs, of which two varieties are modeled: annual costs from annually recurring activity, and annual costs from non-annual recurring activities. In the latter case, the non-annual recurring costs is converted into average annual costs and assigned as an annually recurring cost (e.g. an assessment performed every seven years is modeled as annual costs, where the annual value is the total recurring cost divided by seven).

The cumulative total costs across the full analysis period are summarized in Section 4.3.3. The net costs of the proposed rule (cost savings) is estimated as the difference in total costs between the proposed rule and the baseline, which is also shown in Section 4.3.3.

4.3.3. Summary of Total Costs and Cost Savings

Costs are aggregated by compliance method to estimate total costs, by year, for the baseline and proposed rule. The incremental effect of the proposed rule is estimated by taking the difference in total costs relative to the baseline. Costs are then aggregated across all years in the analysis period and annualized.

Exhibit 4-11 summarizes the annualized cost for miles complying using the proposed rule option, by rule provision, for Scenario 1: \$22 - \$24 million per year.

Exhibit 4-11: Scenario 1 Annualized Proposed Rule Cost, by Provision (2020 to 2039)

Proposed Rule Provision	3% Discount Rate	7% Discount Rate
(a)(4)(i) Integrity Management Program Requirements	$65,948	$71,337
(a)(4)(ii)(A) & (B) ILI & (a)(4)(iv)(A) CIS Initial Assess & Reassess	$304,461	$255,779
(a)(4)(iii)(B) Remediation and repair criteria	$962,136	$1,040,763
Maintenance Surveys (a)(4)(iv):	$0	
(B) Cathodic Protection pipe-to-soil test station	$279,833	$302,701
(C) Line of Sight Markings	$60,156	$65,072
(D) & (E) Interference & Depth of Cover	$329,978	$356,944
(F) & (G) RoW Patrol and Leakage Surveys	$16,197,559	$13,607,634
(H) Casings	$0	$0
(a)(4)(v) Remote Control Valves	$5,433,849	$5,877,913
(a)(4)(vi) Documentation	$48,519	$52,484
Total Rule Option Cost	**$23,682,439**	**$21,630,628**

Exhibit 4-12 and Exhibit 4-13 summarize how this cost compares to baseline costs, showing the total and annualized costs for the baseline and with the proposed rule option available. PHMSA estimates annualized cost savings of approximately $54 to $55 million for Scenario 1.

Exhibit 4-12: Scenario 1 Total Proposed Rule Cost Savings (NPV, 2020 to 2039, millions)

	Discount Rate	
Baseline	3%	7%
Pipe Replacement	$3,075	$2,190
Special Permits	$134	$85
Total Cost	**$3,209**	**$2,275**
Proposed Rule	3%	7%
Pipe Replacement	$2,020	$1,439
Special Permits	$37	$24
New Compliance Method	$354	$231
Total Cost	**$2,412**	**$1,693**
Net Total Cost	**-$797**	**-$582**

Exhibit 4-13: Scenario 1 Annualized Proposed Rule Cost Savings (2020 – 2039, millions)

	Discount Rate	
Baseline*	**3%**	**7%**
Pipe Replacement	$206.7	$206.7
Special Permits	$9.0	$8.0
Total Cost	**$215.7**	**$214.7**
Proposed Rule	**3%**	**7%**
Pipe Replacement	$135.8	$133.8
Special Permits	$2.5	$2.2
New Compliance Method	$23.8	$21.8
Total Cost	$162.1	$159.8
Net Annualized Cost	**-$53.6**	**-$54.9**

*Operators also have the option to use a pressure test or pressure reduction to manage the class location change. To the extent operators' find the new class location MAOP acceptable, the decision by operators to use these options is not affected by the addition of the proposed rule compliance method. Therefore, the rule has no incremental effect on these compliance options.

Exhibit 4-14 summarizes annualized compliance costs on a per-mile basis for the three compliance options included in the analysis.[28]

Exhibit 4-14: Scenario 2 Total Proposed Rule Cost Savings (NPV, 2020 to 2039, millions)

	Discount Rate	
Baseline	**3%**	**7%**
Pipe Replacement	$4,860	$3,461
Special Permits	$134	$85
Total Cost	$4,994	$3,546
Proposed Rule	**3%**	**7%**
Pipe Replacement	$3,193	$2,274
Special Permits	$37	$24
Proposed Rule Method	$514	$337
Total Cost	**$3,747**	**$2,635**
Net Total Cost of the Proposed Rule	**-$1,246**	**-$911**

[28] The Special Permit option and new compliance option include a mix of one-time, annual, and otherwise recurring costs, so compliance cost outlays are not uniform in each year. The annualized costs presented convert this "lumpy" time-series of cost outlays into an annual equivalent value for the purposes of comparison across options. Annualized costs capture, but do not explicitly show, differences in the mix of one-time and other costs that comprise the full cost of compliance over the 20-year analysis period. For example, as detailed in this PRIA, although the new compliance option introduced in the NPRM is less expensive than the Special Permit overall on an annualized basis, it may include more up-front costs than the Special Permit option, but less in the way of recurring costs.

Exhibit 4-15 summarizes annualized compliance costs on a per-mile basis for the three compliance options included in the analysis.[29]

Exhibit 4-15: Annualized Cost per Mile for Class Change Compliance Methods, Scenario 1 (2020 – 2039)

Compliance Option	Annualized Cost per Mile	
	3% Discount Rate	7% Discount Rate
Pipe Replacement	$3,091,255	$3,091,255
Special Permit	$1,063,448	$950,255
New Compliance Option	$814,524	$745,228

Exhibit 4-16 summarizes the annualized cost for miles complying using the proposed rule option, by rule provision, for Scenario 2: $32 - $35 million per year.

Exhibit 4-16: Scenario 2 Annualized Proposed Rule Cost, by Provision (2020 to 2039)

Proposed Rule Provision	3% Discount Rate	7% Discount Rate
(a)(4)(i) Integrity Management Program Requirements	$109,132	$109,132
(a)(4)(ii)(A) & (B) ILI & (a)(4)(iv)(A) CIS Initial Assess & Reassess	$448,060	$391,290
(a)(4)(iii)(B) Remediation and repair criteria	$1,535,616	$1,535,616
Maintenance Surveys (a)(4)(iv):	$0	
(B) Cathodic Protection pipe-to-soil test station	$441,463	$441,463
(C) Line of Sight Markings	$94,902	$94,902
(D) & (E) Interference & Depth of Cover	$520,571	$520,571
(F) & (G) RoW Patrol and Leakage Surveys	$22,724,780	$19,845,531
(H) Casings	$0	$0
(a)(4)(v) Remote Control Valves	$8,572,416	$8,572,416
(a)(4)(vi) Documentation	$76,543	$76,543
Total Rule Option Cost	**$34,523,484**	**$31,587,465**

Exhibit 4-17 and Exhibit 4-18 summarize how Scenario 2 proposed rule costs compare to baseline costs, in terms of the total and annualized costs compared to the baseline. PHMSA estimates annualized cost savings of approximately $84 to $86 million for Scenario 2.

[29] The Special Permit option and new compliance option include a mix of one-time, annual, and otherwise recurring costs (e.g., every five years), so compliance cost outlays are not uniform in each year. The annualized costs presented converts this "lumpy" time-series of cost outlays into an annual equivalent value for the purposes of comparison across options. Annualized costs capture, but do not explicitly show, differences in the mix of one-time and other costs that comprise the full cost of compliance over the 20-year analysis period. For example, as detailed in this PRIA, although the new compliance option is less expensive than the Special Permit overall on an annualized basis, the rule option includes more up-front costs than the Special Permit option, but less in the way of recurring cost.

Exhibit 4-17: Scenario 2 Total Proposed Rule Cost Savings (NPV, 2020 to 2039, millions)

	Discount Rate	
Baseline	**3%**	**7%**
Pipe Replacement	$4,858	$3,459
Special Permits	$133	$85
Total Cost	$4,991	$3,544
Proposed Rule	**3%**	**7%**
Pipe Replacement	$3,192	$2,273
Special Permits	$37	$24
Proposed Rule Method	$514	$335
Total Cost	**$3,743**	**$2,631**
Net Total Cost of the Proposed Rule	**-$1,249**	**-$913**

Exhibit 4-18: Scenario 2 Annualized Proposed Rule Cost Savings (2020 – 2039, millions)

	Discount Rate	
Baseline*	**3%**	**7%**
Pipe Replacement	$326.5	$326.5
Special Permits	$9.0	$8.0
Total Cost	**$335.5**	**$334.5**
Proposed Rule	**3%**	**7%**
Pipe Replacement	$214.5	$214.5
Special Permits	$2.5	$2.2
Proposed Rule Method	$34.5	$31.6
Total Cost	**$251.6**	**$248.4**
Net Annualized Cost of the Proposed Rule	**-$83.9**	**-$86.2**

*Operators also have the option to use a pressure test or pressure reduction to manage the class location change. To the extent operators' find the new class location MAOP acceptable, the decision by operators to use these options is not affected by the addition of the proposed rule compliance method. Therefore, the rule has no incremental effect on these compliance options.

The cost savings this rule would generate are driven almost entirely by the switch from pipe replacement to the proposed rule method, and the overall lower cost of compliance for the proposed rule option, compared to pipe replacement.

5 Historical Incident Analysis

PHMSA analyzed historical, onshore gas transmission incidents from 2010 to 2018, in conjunction with Annual Report data to determine whether any additional incidents should be expected under the proposed rule. PHMSA focused on incidents between 2010 and 2018 because pipeline operators reported these incidents to PHMSA using a consistent method, and pipeline inspection requirements prior to 2010 are inconsistent with current standards. The Annual Report data for 2010-2011 do not specify mileage by consequence location (i.e., HCA, non-HCA). Therefore, when using the incident data in conjunction with Annual Report data to assess incidents inside or outside of HCAs, PHMSA was limited to the data from the period between 2012 and 2018. PHMSA approximated the behavior of operators with and without Special Permits (and the associated IMP) with pipelines inside and outside of HCAs, as operators with pipelines in HCAs are required in the baseline to have an IMP similar to that required under the proposed rule.

The purpose of this analysis is to compare the incident rate for pipes operating under different conditions following a change from Class 1 to Class 3. PHMSA compares incidents for a change managed using pipe replacement in a non-IM setting against anticipated incidents using the proposed rule option:

- **Baseline:** Operator replaces the non-HCA (i.e. non-IM) pipe segment to comply with the Class 3 design, and continues to operate the segment under Class 3 without an IMP;
- **Proposed Rule:** Operator does not replace the non-HCA pipe segment, so the segment is still using Class 1 pressure specifications, but adopts the proposed rule option. The segment is operated with Class 1 pressure specifications but with an IMP.

In the baseline, PHMSA expects the vast majority of operators to perform pipe replacement when a class location changes from C1 to C3. Using available information in the incident data, PHMSA represents this case as a non-HCA segment with Class 3 pressure specifications (i.e. Class 3, but without an IMP). PHMSA reviewed historical incidents for pipeline mileage in Class 3 non-HCA locations to serve as a proxy for this population: Class 3, no IMP. Exhibit 5-1 summarizes the number of incidents, and number of miles of, onshore Class 3 pipelines outside HCAs. During the period 2012-2017, the probability of an incident was, on average, 0.00044 incidents per mile per year.

Exhibit 5-1: Summary of Incidents and Mileage for Onshore Class 3 Pipelines Outside HCAs

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2012 to 2018 Average
Number of Incidents	3	3	8	4	10	8	5	2	14	7.6
Number of Miles			16,884	17,606	17,605	17,838	17,275	16,835	16,723	17,252
Probability of Incident[a]			0.00047	0.00023	0.00057	0.00045	0.00029	0.00012	0.00084	0.00044

a. Number of incidents divided by number of miles.
* Miles by Class and Consequence Type were not reported in these two years
Source: PHMSA, 2018b.

With the proposed rule, PHMSA expects some operators to switch from pipe replacement to the new proposed rule method and its associated IMP and other requirements. Conceptually in this case, these are pipelines retaining their original Class 1 pressure specifications, but operating in a Class 3 location with an IMP in place. To represent this population in the incident data, PHMSA examined Class 1 HCA incidents such that the HCA-specification captures the IMP elements for Class 1-operated segments. Thus, PHMSA reviewed historical incidents and pipeline mileage in Class 1 HCA locations. PHMSA limited the incidents and mileage to pipelines that would qualify for the rule case ("affected" pipelines) those that are piggable, protected, ≤ 72 percent SMYS, and with complete records (did not establish MAOP by 49 CFR §192.619(c)).

Exhibit 5-2 summarizes the number of incidents at, and number of miles of, onshore Class 1 pipelines in HCAs. During the period between 2012 and 2018, the probability of an incident was, on average, 0.00025 incidents per mile per year.

Exhibit 5-2: Summary of Incidents and Mileage at Affected[a] Onshore Class 1 Pipelines in HCAs

	2010	2011	2012	2013	2014	2015	2016	2017	2018	Average
Number of Incidents			0	0	1	0	1	0	0	0.3
Number of Miles			1,201	1,130	1,133	1,122	1,153	1,109	1,123	1,139
Probability of Incident[b]			0	0	0.00088	0	0.00087	0	0	0.00025

a. Affected pipelines are those that would qualify for the rule case.
b. Number of incidents divided by number of miles.
* Mileage data by Class and Consequence Type were not reported in these two years.
Source: PHMSA, 2018b.

The Class 3 non-HCA incident rate is less than the Class 1 HCA incident rate by an amount that is not statistically significant.[30] The hypothesis of a significantly higher incident rate for Class 1 HCA pipeline compared to Class 3 non-HCA pipeline is rejected.[31, 32]

30 The result shows a decrease in the incident rate of 0.00019 per mile per year.
31 The hypothesis for this statistical test is that the mean of the annual incident rate per mile for onshore Class 1 pipelines in HCAs is greater than that for onshore Class 3 pipelines outside of HCAs. A two-sample t-test assuming unequal variances calculates a t-statistic of -1.03, which is less that the one-tail critical value of 1.83, thus the data fails to demonstrate that Class 1 HCA pipeline has a significantly higher incident rate at the 5% confidence level.
32 The C1 to C3 location segment will have significantly higher standards for identifying, assessing, mitigating, and monitoring pipeline threats that cause incidents along a pipeline, such as material failure, corrosion, excavation damage, natural force damage, and incorrect operation.

6 Analysis Required Under Applicable Statutes and Executive Orders

This section describes administrative requirements for regulatory analyses and summarizes PHMSA's findings for the proposed rule.

6.1 Executive Orders 12866 and 13771

The proposed rulemaking is considered to be a significant regulatory action under section 3(f) of Executive Order (E.O.) 12866. The NPRM was reviewed by the Office of Management and Budget in accordance with E.O. 12866 and is consistent with its requirements. This rule is also considered to be significant under the Department of Transportation's policies at 49 CFR part 5.

E.O. 12866 requires agencies to regulate in the "most cost-effective manner," to make a "reasoned determination that the benefits of the intended regulation justify its costs," and to develop regulations that "impose the least burden on society." In this proposed rulemaking, PHMSA seeks to accomplish the directives of E.O. 12866, in part, by considering public comment on the potential impacts of the proposed amendments to part 193.

This proposed rule is also expected to be a deregulatory action under E.O. 13771. The annualized cost savings of this proposed rule using a 7 percent discount rate are estimated to be approximately $54.9 to $86.0 million (discounted to 2020 in 2018 dollars, as described above in this PRIA). At a 7 percent discount rate and expressed in 2016 dollars, annualized cost will be approximately $52.7 to $82.6 million per year. Projecting the current analysis into perpetuity, the annualized costs would be $49.5 to $77.2 million per year, expressed in 2016 dollars at a 7 percent discount rate. The final step, conducted for OIRA reporting, is to convert the annualized numbers into values discounted back to 2016 and in 2016 dollars. Thus, discounting back to 2016 present-value terms, the annualized cost will be approximately $37.8 to $58.9 million dollars at a 7 percent discount rate and in 2016 dollars.

6.2 Initial Regulatory Flexibility Act Analysis (IRFA)

The Regulatory Flexibility Act (RFA) of 1980 requires federal agencies to consider the impact of their rules on small entities,[33] to analyze alternatives that minimize those impacts, and to make their analyses available for public comments. The RFA is concerned with three types of small entities: small businesses, small nonprofits, and small government jurisdictions.

The RFA describes the regulatory flexibility analyses and procedures a federal agency must complete unless they certify that the rule, if promulgated, would not affect a substantial number of small entities. A statement of factual basis must support this certification with an evaluation of the number of small entities affected by the proposed action, expected costs affecting these entities, and the economic impacts on the entities. The RFA requires that an agency prepare an Initial Regulatory Flexibility Analysis (IRFA) for any proposed rule. The proposed rule may affect small businesses that operate onshore natural gas pipelines. This IRFA documents PHMSA's analysis of potential small business impacts of the proposed rule.

[33] Section 603(c) of the RFA provides examples of such alternatives as: (1) the establishment of differing compliance or reporting requirements or timetables that take into account the resources available to small entities; (2) the clarification, consolidation, or simplification of compliance and reporting requirements under the rule for such small entities; (3) the use of performance rather than design standards; and (4) an exemption from coverage of the rule, or any part thereof, for such small entities.

6.2.1. Analysis Approach

In accordance with RFA requirements, PHMSA assessed whether the rule would have "a significant impact on a substantial number of small entities" (SISNOSE). This assessment involves the following general steps:

1. Identifying the operators of gas transmission pipelines affected by the proposed rule, and the domestic parent entities for affected operators;
2. Determining which of those domestic parent entities are small entities, based on Small Business Administration (SBA) size criteria;
3. Assessing the potential impact of the proposed rule on those small entities by comparing the estimated entity-level annualized compliance cost to entity-level revenue (i.e., applying a "sales test"); and,
4. Assessing whether those small entities incurring potentially significant impacts represent a substantial number of small entities.

As described below, PHMSA finds that the proposed rule would provide regulatory flexibility and the opportunity for cost savings for the 254 small entities operating Class 1 gas transmission pipelines, and will not result in a SISNOSE.

6.2.2. Definition of a Small Entity

The proposed rule affects entities operating Class 1 gas transmission pipelines, including privately and publicly held businesses as well as municipal entities. The RFA incorporates and uses the definition of "small business" established in SBA regulations. SBA has established size standards for various types of economic activities, or industries, under the North American Industry Classification System (NAICS). These size standards generally define small businesses based on the number of employees or annual receipts, and the standards vary across different industries. For example, Exhibit 6-1 presents the size standards for the pipeline transportation industry.

Exhibit 6-1: Small business size standards: Subsector 486 – Pipeline Transportation

NAICS Code	Description	Standard
486110	Pipeline Transportation of Crude Oil	1,500 employees
486210	Pipeline Transportation of Natural Gas	$30 million
486910	Pipeline Transportation of Refined Petroleum Products	1,500 employees
486990	All Other Pipeline Transportation	$40.5 million

Source: SBA (2019)
NAICS = North American Industrial Classification System
SBA = Small Business Administration

Note that the SBA definition of a small business applies to the parent company and all affiliates as a single entity. The RFA defines "small governmental jurisdiction" as the government of a city, county, town, township, village, school district, or special district with a population of less than 50,000. For the purposes of the RFA, PHMSA does not consider States and Tribal governments to be small governments. Furthermore, the RFA defines "small organization" as any "not-for-profit enterprise which is independently owned and operated and is not dominant in its field."[34]

6.2.3. Small Entities Affected by the Proposed Rule

PHMSA uses operator Annual Report data (PHMSA 2020a), PHMSA's Dun & Bradstreet (D&B) database (PHMSA 2020b), and supplemental research to identify small entities operating Class 1 pipelines that fall within the applicable SBA threshold. The overall population and number of affected operators has been obtained from PHMSA Annual Report data. The D&B data used to identify the subset of entities that are "small entities" under the RFA include each operator's primary NAICS, estimates of employment and annual revenue, and parent entity information. PHMSA also conducted additional operator-specific research to verify potentially anomalous D&B values, and to populate missing NAICS, employment, and revenue data. Key data sources for this effort include secondary sources such as Security and Exchange Commission (SEC) filings, State public utility commission dockets, and company websites.

There are currently 1,099 operators of onshore natural gas transmission pipelines, and approximately 85 percent, or 939 operators, of those operate Class 1 pipelines. Operators of Class 1 pipelines are owned by 324 parent entities, and of these, 254 are small entities. Small entities operate 5,200 miles of Class 1 pipeline, which is a very small share of all Class 1 pipelines, about 2.2 percent.

Exhibit 6-2: Small Entities Affected by the Proposed Rule

	Class 1 Gas Transmission
Number of Operators	939
Number of Parent Entities	324
Number of Small Entities	254
Small Entity Miles	5,164
Percent of total class 1 miles	2.2%

Source: PHMSA 2020a, 2020b

6.2.4. Small Entity Cost Savings and Impacts

As previously presented in Exhibit 4-13 and 4-17, PHMSA estimates annualized cost savings due to the proposed rule for two mileage Scenarios:

- Scenario 1:
  - 77.6 miles per year changing from Class 1 to Class 3
  - Annualized cost savings of $54 to $55 million (3 and 7 percent discount rate, respectively)
- Scenario 2:
  - 117.6 miles per year changing from Class 1 to Class 3
  - Annualized cost savings of $84 to $86 million (3 and 7 percent discount rate, respectively)

The proposed rule does not eliminate currently available options for management of C1 to C3 changes, but rather provides flexibility to operators by enabling the use of another compliance option. Since the new proposed option costs less than the other predominately used options – replacement and special

[34] 5 U.S.C. § 601(4).

permit – small entities have the opportunity to achieve cost savings to the extent they need to manage class location changes in the future that meet the rule's applicability criteria.

The quantity, character, and location of future class changes are all highly uncertain, particularly on a year-to-year basis. And, in any given year, only a subset of operators will engage in C1 to C3 changes. PHMSA is not able to develop an annual forecast describing specific pipeline segments changing classes or to what extent those changes will be managed by small versus large operators. Over the 20-year period of analysis, PHMSA assumes that each operator will manage a share of the future C1 to C3 changes that is proportional to each operator's Class 1 miles. Future C1 to C3 miles under each Scenario, and the associated cost savings, are allocated to individual small entities using two steps:

- Allocate annualized cost savings to large and small entities based on the proportion of total Class 1 miles that are operated by large and small entities; and,
- Allocate small-entity cost savings to each individual small entity based on the proportion of total small-entity Class 1 miles operated by each small entity.

Small entities operate 2.2 percent of all Class 1 miles that may be affected by the rule. PHMSA therefore estimates that small entities will manage 1.7 to 2.6 miles of pipeline experiencing C1 to C3 changes, annually, in Scenarios 1 and 2, respectively.

Annualized cost savings for small entities are estimated to be $1.17 – $1.19 million in Scenario 1, using 3 and 7 percent discount rates, respectively; annualized small entity savings are estimated to be $1.8 - $1.9 in Scenario 2. Under Scenario 1, the average annual cost savings per small entity are $4,700, with a median savings of $1,500 per year. Under Scenario 2, the average per-entity annual savings are $7,400, with a median of $2,300.

Next, PHMSA compared each entity's annualized cost savings with their annual revenue, obtained from D&B, as previously described. Based on the 7 percent discounted cost savings, and reported revenues, PHMSA estimates that approximately 66 – 83 of the 254 small entity operators may experience cost savings in excess of one percent of annual revenues, depending on the Scenario. However, as noted above, PHMSA's allocation of cost savings to individual operators does not take into account operator-specific circumstances or segment characteristics that determine whether a given entity will require a future C1 to C3 change. In addition, revenues reported through secondary data sources are subject to uncertainty.

6.2.5. Discussion and Conclusion

As noted above, to the extent small entities need to manage future C1 to C3 changes, the proposed rule option provides regulatory flexibility and the potential for cost savings relative to existing compliance options.

Only about 1 percent of Class 1 pipeline miles are estimated to be affected by a Cl to C3 change *in total* over the next 20 years. Based on PHMSA's high-end Scenario 2 estimate of 117.6 miles per year, only 2,352 miles will make this change over the next 20 years. Annually, the proposed rule affects 0.05 percent Class 1 miles. The characteristics of this small subset of pipeline miles (or segments) that will ultimately determine the extent to which large and small entities ultimately use the proposed rule option. Though, given that small entities operate only about 2 percent of Class 1 miles, large entities in the aggregate are more likely to experience a segment requiring a C1 to C3 change.

Although the savings are presented here on an annualized basis, PHMSA expects that most entities will not manage a C1 to C3 change in any given year. For instance, PHMSA's estimate of 1.7 to 2.6 miles per year of C1 to C3 changes managed by small entities (Scenarios 1 and 2), considered against

PHMSA's estimated average segment length of 0.26 miles,[35] suggests an average of 7 to 10 segments experiencing a class change across the entire industry per year. If operators only manage one segment per year, then 7 to 10 small entities (or fewer if operators manage multiple segments in one year) may manage a C1 to C3 change per year, out of 254 total small entities.

Based on this analysis, PHMSA has determined that the proposed rule would not have a significant economic impact on a substantial number of small entities.

6.3 Unfunded Mandates Reform Act (UMRA) Analysis

Section 201 of the UMRA of 1995, 5 U.S.C. 1531, requires that Federal agencies assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under UMRA section 202, PHMSA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that might result in expenditures by State, local, and Tribal governments, in the aggregate, or by the private sector, of $100 million (adjusted annually for inflation) or more in any one year.

Based on the cost estimates detailed in Section 4, PHMSA determined that compliance costs for any State, local, and Tribal government, in the aggregated, or private sector in any given year will be below the threshold set in UMRA.

6.4 Paperwork Reduction Act (PRA) of 1995

The PRA requires that agencies submit a supporting statement to OMB for any information collection that solicits the same data from more than nine parties. The PRA seeks to ensure that Federal agencies balance their need to collect information with the paperwork burden imposed on the public by the collection.

Under the PRA, 5 U.S.C. 1320.3, the definition of "information collection" includes activities required by regulations, such as permit development, monitoring, record keeping, and reporting. The term "burden" refers to the "time, effort, or financial resources" the public expends to provide information to or for a Federal agency, or to otherwise fulfill statutory or regulatory requirements. PRA paperwork burden is measured in terms of annual time and financial resources the public devotes to meet one-time and recurring information requests (44 U.S.C. 3502(2); 5 C.F.R. 1320.3(b)). Information collection activities may include:

- Reviewing instructions;
- Using technology to collect, process, and disclose information;
- Adjusting existing practices to comply with requirements;
- Searching data sources;
- Completing and reviewing the response; and
- Transmitting or disclosing information.

Agencies must provide information to OMB on the parties affected, the annual reporting burden, the annualized cost of responding to the information collection, and whether the request significantly impacts a substantial number of small entities. An agency may not conduct or sponsor, and a person is

[35] Per PHMSA's estimate described in Section 3.1 and Appendix C.1 for additional detail.

not required to respond to, an information collection unless it displays a currently valid OMB control number.

OMB has previously approved the information collection requirements contained in the existing pipeline safety regulations under the provisions of the PRA.

The proposed rule would change the information collection requirements associated with certain gas transmission pipelines. PHMSA estimates the reporting and recordkeeping burden for provisions in Section 4, and is submitting a revised information collection request to OMB for approval.

6.5 E.O. 13132: Federalism

E.O. 13132 requires PHMSA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." Policies that have federalism implications are defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government."

Under section 6 of E.O. 13132, PHMSA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments or unless PHMSA consults with State and local officials early in the process of developing the regulation. PHMSA also may not issue a regulation that has federalism implications and that preempts State law, unless the Agency consults with State and local officials early in the process of developing the regulation.

PHMSA has concluded that this proposed action would not have federalism implications, because it does not impose any direct compliance costs on State or local governments.

6.6 E.O. 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

E.O. 13211 requires agencies to prepare a Statement of Energy Effects when undertaking certain agency actions. Such Statements of Energy Effects shall describe the effects of certain regulatory actions on energy supply, distribution, or use, notably: (i) any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increased use of foreign supplies) should the proposal be implemented, and (ii) reasonable alternatives to the action with adverse energy effects and the expected effects of such alternatives on energy supply, distribution, and use.

The OMB implementation memorandum for E.O. 13211 outlines specific criteria for assessing whether a regulation constitutes a "significant energy action" and would have a "significant adverse effect on the supply, distribution or use of energy." Those criteria include:

- Reductions in crude oil supply in excess of 10,000 barrels per day;
- Reductions in fuel production in excess of 4,000 barrels per day;
- Reductions in coal production in excess of 5 million tons per year;
- Reductions in natural gas production in excess of 25 million Mcf per year;

- Reductions in electricity production in excess of 1 billion kilowatt-hours per year, or in excess of 500 megawatts of installed capacity;
- Increases in the cost of energy production in excess of 1 percent;
- Increases in the cost of energy distribution in excess of 1 percent;
- Significant increases in dependence on foreign supplies of energy; or
- Having other similar adverse outcomes, particularly unintended ones.

This proposed rule is not expected to have significant impacts on energy supply, distribution, or use.

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Appendix A: Description of the Proposed Integrity Assessment Program for Class Location Changes

Under existing § 192.611 requirements, operators are required to confirm or revise their MAOP when changing a pipe's class location. Currently, if a pipe segment's hoop stress and established MAOP are not commensurate with the present class location, and the segment is in satisfactory physical condition, the MAOP of that segment of pipeline may be revised by an MAOP reduction, previous or new pressure test, or pipe replacement. In lieu of pipe replacement, pressure test, or pressure reduction, current regulations also provide a mechanism for operators to perform alternative risk control activities, based on integrity management principles and requirements, via special permit, as described above.

PHMSA is proposing to add § 192.618 to effectively codify conditions under which this option is available without the requirement of a Special Permit.

Segments changing from a C1 to C3 location must meet the applicability criteria, pipeline integrity assessments, remediation, maintenance surveys, remote control valves, documentation, and notification requirements summarized below:

Class 1 to 3 Location Segment Applicability Criteria

First, PHMSA is proposing under that the MAOP may be confirmed or revised by designating affected pipe segment as an HCA and including it in an operator's IM program, subject to meeting the following additional conditions:

- The C1 to C3 location segment change must have occurred after the effective date of the rule;
- The pipe segment must be able to accommodate an instrumented in-line inspection tool;
- The hoop stress corresponding to MAOP of the C1 to C3 location segment must not exceed 72 percent of SMYS in the class 3 location; and,
- The pipe segment must not: be bare pipe, contain wrinkle bends, lack material records for certain pipe attributes or a pressure test, contain certain kinds of welds, or have a history of cracking.

Pipeline Integrity Assessments

PHMSA proposes that the C1 to C3 location segment must have an initial integrity assessment within 24 months and be reassessed using an in-line inspection high resolution magnetic flux leakage tool, and a high resolution deformation tool with sensors and extension arms outside the tool cups, or an equivalent internal inspection device. The operator must also conduct periodic reassessments using instrumented in-line inspection tools in accordance with the assessment intervals in § 192.939.

Remediation

In addition to the evaluation, repair, and remediation scheduling requirements in § 192.933, operators must comply with additional remediation requirements as proposed including:

- **Immediate repair condition**. Pipe wall thickness loss greater than or equal to 80 percent;
- **One-year condition**. Predicted failure pressure less than 1.39 times MAOP or pipe wall thickness loss greater than 40 percent;

- **Monitored condition**. Predicted failure pressure greater than or equal to 1.39 times MAOP or pipe wall thickness loss less than or equal to 40 percent; or,
- Special requirements for crack anomalies.

Maintenance Surveys

PHMSA proposes additional maintenance surveys, and remediation of unprotected pipe segments. The additional maintenance surveys include:

- **Close interval surveys** with an on/off current at a maximum 5-foot spacing, evaluate in accordance with § 192.463 for unprotected pipe segments, and remediate the unprotected pipe segments within one year;
- At least one (1) **cathodic protection** (CP) pipe-to-soil test station must be located within the C1 to C3 location segment with a maximum spacing between test stations of one-half mile spacing;
- Operator must install and maintain **line-of-sight markings** on the C1 to C3 location segment except in agricultural areas or large water crossings such as lakes where line-of-sight signage is not practical;
- **Interference surveys** must be conducted to address induced alternating current (AC) from parallel electric transmission lines and other interference issues such as direct current (DC) that may affect the C1 to C3 location segment. An induced AC or DC program and remediation plan to protect the C1 to C3 location segment from corrosion caused by stray currents must be in place and implemented within one (1) year of the interference survey;
- **Depth of cover** must be in accordance with § 192.327 for a Class 1 location or be remediated through additional markers, lowering the pipe, adding cover, or installing safety barriers;
- **Right-of-way** patrols to meet § 192.705 must be conducted on a monthly basis not to exceed 45-days for C1 to C3 location segments;
- **Leakage surveys** to meet § 192.706 must be conducted on a quarterly basis for C1 to C3 location segments; and,
- **Shorted casings** in the C1 to C3 location segment must have the metallic short cleared no later than one (1) year after the short is identified.

Remote Control or Automatic Shut-off Valves

PHMSA proposes the installation of mainline valves on both sides of the C1 to C3 location segment, not to exceed 20 miles apart, and must be operational remote-controlled valves or automatic shutoff valves with pressure sensors on each side of the mainline valves. Additionally, each operator installing remote-control or automatic shutoff valves must have procedures in place allowing them to identify a rupture event within 10 minutes of the initial notification to the operator. Valves installed must be closed as soon as practicable after a rupture is identified, but not to exceed 30 minutes.

Documentation

PHMSA proposes each operator must keep for the life of the C1 to C3 location segment a record of the pipeline assessments, surveys, remediation, maintenance, analyses, and any other action implemented to comply with the proposed option.

Notifications to PHMSA of Integrity Assessment Program for Class 1 to 3 Location Segment Changes

Lastly, PHMSA proposes each operator of a gas pipeline that uses the integrity assessment program for a C1 to C3 location segment notify PHMSA electronically, 18 months prior to end of the 24-month period for pipe class change notification under the proposed option.

Appendix B: Estimating the Annual Quantity of Miles Changing from Class 1 to Class 3

PHMSA proposes that in order for a pipe segment to be eligible for the proposed rule option, the C1 to C3 location segment change must have occurred after the effective date of rule. The regulatory analysis thus requires a baseline of future class location change activity specifically for prospective C1 to C3 changes. The baseline of class location changes is the foundation for analyzing the costs and benefits of the proposed rule. Below PHMSA describes its approach for estimating the baseline quantity of miles changing from C1 to C3 on an annual basis using historical data from Annual Report Part L.

PHMSA estimated the quantity of historical class changes using Annual Report Part L data for 2010 to 2017.[36] For each unique operator, PHMSA calculated the year-to-year change in the number of miles in each class location for each operator's system in each State. This information provides annual changes in the quantity of miles, by class, for each operator, along with changes in total annual miles for each operator. This information provides annual changes in the quantity of miles, by class, for each operator, along with changes in total annual miles for each operator. However, the data are limited in that there is no explicit information about how changes in the quantity of miles by class came about. For example, these data do not explicitly describe or distinguish the quantity of miles that changed from, say, C1 to C3, versus from C2 to C3. In some instances, a C1 to C3 change can be discerned based on how the quantity of miles in other classes changed, or didn't change. In other cases, there is some uncertainty in the class changes that actually occur from one year to the next.

To address these limitations, PHMSA made the following assumptions to estimate the year-to-year mileage changing from C1 to C3:

- C1 to C3 changes are most likely when there is a year-to-year decrease in Class 1 mileage and a year-to-year increase in Class 3 mileage, regardless of any other changes to the system; or when both C1 and C3 miles increase along with total operator mileage, although it is more difficult to discern class changes from new pipelines added to each class in these instances.
- For systems where the total mileage does not change from the previous year:
    - If there is no change in mileage from one year to the next in a given class (e.g., Class 2), then PHMSA assumes that there was no movement of pipelines into or out of that class.
    - If, instead, there are changes from one year to the next in a given class, PHMSA assumes those changes represent pipe that was "redistributed"—i.e., that there was no pipe constructed, bought, sold, or abandoned for that system in that year.

Based on these assumptions, PHMSA identified 18 patterns of annual class changes in the Annual Report data, illustrated in Exhibit B-1. Based on what these data allow one to infer, PHMSA is able to estimate some potential C1 to C3 changes with relative confidence, specifically patterns A – F, where the total system mileage remains constant from year-to-year. Other patterns, G – R, include changes in

[36] Note: There appears to be a data reporting error in year 2015. Nine operators did not properly report their class location data in their 2015 Part L Annual Reports. According to Part L data, significant portions (18 to 567 Class 3 location miles) were not reported. These operators include OPID: #02616, #19160, #00288, #02620, #14435, #32034, #39126, #30749, and #00993. For these nine operators PHMSA assumed their Class 3 pipe in 2015 was the same as the prior year 2014.

the quantity of miles by class that could include C1 to C3, but the extent to which this particular two-class change occurred is less certain (described further below).

Note that, based on the Class 1 column below, PHMSA did not consider any pattern possibilities in which the Class 1 mileage increased or remained the same from the previous year. Similarly, PHMSA did not consider instances where Class 3 mileage decreased or remained the same from the previous year. In addition, because PHMSA assumed that the class location of a pipeline could increase but not decrease, PHMSA only assessed situations where the Class 4 mileage increased or did not change from the previous year.

Exhibit B-1: Class Change Mileage Patterns

Pattern ID	Class 1	Class 2	Class 3	Class 4	Total
A	↓	→	↑	→	→
B	↓	↓	↑	→	→
C	↓	↑	↑	→	→
D	↓	→	↑	↑	→
E	↓	↓	↑	↑	→
F	↓	↑	↑	↑	→
G	↓	→	↑	→	↑
H	↓	↓	↑	→	↑
I	↓	↑	↑	→	↑
J	↓	→	↑	↑	↑
K	↓	↓	↑	↑	↑
L	↓	↑	↑	↑	↑
M	↓	↑	↑	↑	↓
N	↓	↓	↑	↑	↓
O	↓	→	↑	↑	↓
P	↓	↑	↑	→	↓
Q	↓	↓	↑	→	↓
R	↓	→	↑	→	↓

↓ = decrease in mileage from previous year; ↑ = increase in mileage from previous year; → = no change in mileage from previous year

For each pattern A-R, PHMSA estimated the annual mileage that changed from C1 to C3. In patterns where the *total* system mileage remained unchanged from the previous year (scenarios A-F), it is unlikely that pipes were constructed, bought, sold, or abandoned. Therefore, PHMSA assumes that any changes in mileage in A – F are due solely to class location changes. In each of these instances, the total C1 to C3 mileage change is equal to the minimum of the absolute value of the Class 1 decrease and the Class 3 increase.[37]

For example, consider the operator in Exhibit B-2, which shows the operator's quantity of mileage by class location in 2011 and 2012. The table also reports the annual changes in the quantity of miles by class location, which indicate that this instance corresponds to type Scenario C from Exhibit B-1. In this scenario, because the total mileage did not change, PHMSA assumes that 4.0 miles of Class 1

[37] PHMSA notes that scenario E is an exception. Because there is an increase in both class 3 mileage and class 4 mileage, the class 1 to class 3 mileage change is uncertain. However, PHMSA did not find a single instance of scenario E in the Annual Report data for 2010-2017 and therefore groups scenarios A-F together for simplicity.

pipeline move into Class 2 and Class 3 in 2011. Because Class 1 mileage decreased 4.0 miles, but Class 3 mileage only increased by 1.0 mile, the total C1 to C3 mileage change is estimated to be 1.0 mile (the minimum of the two changes).

Exhibit B-2: Pattern C Example

Year	Class 1	Class 2	Class 3	Class 4	Total
2010	443	53	61	0	557
2011	439	56	62	0	557
Year-to-Year Change	-4	+3	+1	0	0

Source: PHMSA, 2018a.

When the *total* system mileage increases or decreases from the previous year (patterns G – R), there is uncertainty regarding the changes that occurred. Any class, regardless of whether there was a change in mileage, could have experienced a change due to class location changes at existing pipelines, or pipelines being constructed, bought, sold, or abandoned. Therefore, for G-R, PHMSA estimates a range of mileage that *may have* changed from C1 to C3 but likely include changes for other reasons as well. PHMSA estimates that at most, the total C1 to C3 mileage change is equal to the absolute value of the Class 1 decrease or the Class 3 increase, whichever is smaller.

Exhibit B-3 summarizes the approach for calculating the quantity of miles changing annual from C1 to C3.

Exhibit B-3: Estimating Class 1 to Class 3 Mileage Changes

Scenarios	Annual C1 to C3 Change
A – F	Equal to min(abs(Class 1 decrease), Class 3 increase)
G – R	Ranges from 0 to min(abs(Class 1 decrease), Class 3 increase)

Each year from 2010 to 2017, PHMSA checked annual report data for each operator's pipelines system to see if it changed in accordance with one of the 18 patterns described above. For example, PHMSA screened for the conditions in Pattern A, and found an average of 9 pipeline *systems* swap some distance of pipe from C1 to C3 per year (Exhibit B-4).

Where the conditions outlined for Patterns A through R matched changes to operator's pipeline systems, PHMSA estimated the total mileage that changed class location. For example, PHMSA screened Annual Report data for the Pattern A conditions and found an average of 17 *miles* change from C1 to C3 locations per year.

The results of the analysis indicate a range of 39 to 355 miles per year changing from C1 to C3, depending on which scenarios are included in the estimate. The resulting range is a byproduct of the limitations in the data available to quantify historical C1 to C3 changes, described above. PHMSA estimates the steady-state quantity of annual changes to be at least 39 miles per year, but depending upon how one interprets and counts the other scenarios (i.e. if all scenarios are counted), an upper-bound estimate is approximately 355 miles per year.

Exhibit B-4: Summary of Historical Class 1 to Class 3 Changes for Gas Transmission

		Possible No. of Systems		*Possible Mileage*	
Scenario	*Long Name*	*Total (2010 to 2017)*	*Average*	*Total (2010 to 2017)*	*Average*
A	A: C1↓, C2 →, C3↑, C4 →, T →	61	9	117	17
B	B: C1↓, C2 ↓, C3↑, C4 →, T →	42	6	68	10
C	C: C1↓, C2 ↑, C3↑, C4 →, T →	65	9	85	12
D	D: C1↓, C2 →, C3↑, C4 ↑, T →	2	0	7	1
E	E: C1↓, C2↓, C3↑, C4↑, T →	0	0	0	0
F	F: C1↓, C2↑, C3↑, C4↑, T →	0	0	0	0
G	G: C1↓, C2 →, C3↑, C4 →, T ↑	25	4	12	2
H	H: C1↓, C2 ↓, C3↑, C4 →, T ↑	67	10	288	41
I	I: C1↓, C2 ↑, C3↑, C4 →, T ↑	165	24	441	63
J	J: C1↓, C2 →, C3↑, C4↑, T ↑	0	0	0	0
K	K: C1↓, C2 ↓, C3↑, C4↑, T ↑	3	0	362	52
L	L: C1↓, C2 ↑, C3↑, C4↑, T ↑	8	1	92	13
M	M: C1↓, C2 ↑, C3↑, C4↑, T ↓	13	2	114	16
N	N: C1↓, C2 ↓, C3↑, C4↑, T ↓	13	2	53	8
O	O: C1↓, C2 →, C3↑, C4↑, T ↓	2	0	20	3
P	P: C1↓, C2 ↑, C3↑, C4 →, T ↓	170	24	445	64
Q	Q: C1↓, C2 ↓, C3↑, C4 →, T ↓	166	24	359	51
R	R: C1↓, C2 →, C3↑, C4 →, T ↓	35	5	22	3
Total Low	Includes only scenarios with more certainty	170	24	276	39
Total High	Includes scenarios with less certainty	2,445	349	2,484	355

Source: PHMSA analysis based on Annual Report Part L data

Exhibit B-5: Estimates of Historical Class 1 to Class 3 Changes for Gas Transmission

	2011	*2012*	*2013*	*2014*	*2015*	*2016*	*2017*	*Average*
Low Estimate	21	57	57	55	40	11	35	**39**
High Estimate	330	400	711	460	152	168	264	**355**
Overall Average								**197**
Overall Median								**104**

Source: PHMSA analysis based on Annual Report Part L data

Annualized Cost Savings with Different Class Change Activity Levels

In Exhibit B-6 below, PHMSA presents sensitivity analysis estimates of annualized cost savings based on varying the quantity of miles changing from Class 1 to Class 3 annually. Total cost savings associated with the proposed rule is proportional to the quantity of miles changing class.

Exhibit B-6: Sensitivity Analysis Estimates of Annualized Cost Savings

Quantity of C1 to C3 Miles	Annualized Cost Savings, (millions, $2018, 3% discount)	Annualized Cost Savings (millions, $2018, 7% discount)
Primary Analysis Range		
197	$149	$153
104	$79	$81
Low- and High-End from Exhibit B-5*		
21	$15.8	$16.3
460	$347	$357

*Excluding the lowest and highest value from the time-series.

Appendix C: Estimating Changes in Compliance Method Utilization Rates

This Appendix describes PHMSA's approach estimating incremental changes in the choice of compliance method relative to the baseline. That is, PHMSA's approach for determining the proportion of baseline Special Permit and replacements that would likely switch to using the new proposed rule method.

C.1 Special Permit

PHMSA estimates the proportion of future baseline special permit miles that could qualify – and switch to – the rule based on public data submitted in 2016 by four operators, who applied for Special Permits for over 260 segments of pipe covering 63.4 miles.[38] Of the 260 segments, 238 were in relation to C1 to C3 changes, or 59 miles. Thus, the use of the Special Permit option averaged 7.4 miles per year from 2010 to 2017. These data include detailed segment characteristics that allow PHMSA to identify qualifying segments. PHMSA estimates that approximately 72 percent of the miles managed via Special Permit in the baseline would likely qualify to use to new proposed rule method, in terms of the material properties and other characteristics required under § 192.618. These operators switching from the Special Permit program in the baseline to the proposed rule method achieve regulatory relief primarily from the absence of the Special Permit application and renewal process.

PHMSA's estimates that 42.7 of the 59.1 miles that have received a Special Permit to avoid pipe replacement, testing, or pressure reduction would qualify to use the proposed rule option. PHMSA's estimate of the quantity of mileage in segments likely qualifying for the proposed rule option includes all segments with the following characteristics that are or were covered by such a Special Permit (consistent with Section 2.2):

- The hoop stress corresponding to MAOP of the C1 to C3 location segment must not exceed 72 percent of SMYS in the class 3 location;
- The pipe segment must be able to accommodate an instrumented in-line inspection tool;
- The pipe segment must not be bare pipe;
- The segment has been pressure-tested;
- The pipe segment must not have a history of cracking;
- The operator installed mainline valve within 10 miles of the pipe segment; and
- The operator has retained material records for the pipeline segment.

The average length for these qualifying segments is 1,392 feet (0.26 miles).

Exhibit C-1: Segment Length and Quantity by Category

Segment Category	*192.618 Qualified Segments*	*Unqualified Segments*	*All C1 to C3 Segments*	***All Segments***
No. of Segments	162	76	238	260

[38] This data can be accessed at regulations.gov in dockets: Tennessee Gas Pipeline Company (Docket No. PHMSA-2016-0004), Southern Natural Gas Company (Docket No. PHMSA-2016-0006), El Paso Natural Gas Company (Docket No. PHMSA-2016-0007), Colorado Interstate Gas Company (Docket No. PHMSA-2016-0008).

Segment Category	*192.618 Qualified Segments*	*Unqualified Segments*	*All C1 to C3 Segments*	*All Segments*
Total Miles	42.7	16.3	59.1	63.4
Average Segment Length (mi.)	0.26	0.22	0.26	0.24
Distribution by Consequence Area				
HCA	18%			16%
MCA	49%			45%
Non-HCA/MCA	34%			40%

Also, PHMSA notes that the historical special permit application data include a field that indicating whether a given segment is located in an HCA. The historical data also include information describing the number of dwellings located near each pipeline segment.[39] PHMSA used this information to determine whether some non-HCA segments where potential future MCAs. An MCA segment is in an onshore area where the potential impact circle contains five or more buildings intended for human occupancy, at the edge of pavement for a designated interstate, freeway, expressway, and other principal four-lane arterial roadway. PHMSA therefore identified segments located near five or more dwellings (and not in an HCA) to estimate the proportion of potential MCA-qualifying segments (28 miles). The remaining segments were located near four or fewer dwellings, and are included as non-HCA/MCA segments. Exhibit C-1 summarizing these data by consequence area type, indicating that more than half of the segments are either HCA or MCA segments.

C.2 Pipe Replacement

With respect to those using the pipe replacement method in the baseline, the historical Special Permit application data do not provide insight to characterize the proportion that would switch from replacement to the rule option. But, using a similar approach relying on Annual Report data (Part K, D, R, and Q), PHMSA estimates the proportion of all Class 1 miles – prospective future class changes – that meet specific screening criteria indicative of the ability to use the proposed rule option (per criteria in Appendix A: Description of the Proposed Integrity Assessment Program for Class Location Changes). Based on these data, PHMSA estimates that 34 percent of miles managed via replacement in the baseline will switch to the proposed rule option. First, PHMSA used annual report data to identify the set of Class 1 mileage characteristics that are generally compatible with the proposed rule requirements:

- The hoop stress corresponding to MAOP of the C1 to C3 location segment must not exceed 72 percent of SMYS in the class 3 location (AR Part K);
- The pipe segment must be able to accommodate an instrumented in-line inspection tool (AR Part R);
- The pipe segment must not be bare pipe (AR Part D); and
- The operator has retained material records for the pipeline segment (AR Part Q, data only for HCAs)

[39] The term "near" refers to the number of buildings within the area that extends axially along the length of the pipeline from the outermost edge of the potential impact circle.

The annual report data are not sufficiently detailed to enable a comprehensive screening of pipelines for *all* requirements and criteria under the proposed §192.8. According to the 2017 data, out of 232,768 total onshore Class 1 miles, there are 1,109 HCA miles that fit all of the above screening criteria, and 145,589 non-HCA miles. In total, this is 146,698 miles, or about 63 percent, of Class 1 miles as potential candidates to be managed under the rule option in the event of a future C1 to C3 change. PHMSA acknowledges, however, that this estimate represents essentially an upper-bound value given the limitations in the screening data (particularly for non-HCAs) given that PHMSA is not able to screen non-HCA miles for the presence of complete records.

A different, lower-bound, concept for estimating the overall population of good, or likely, candidates to utilize the rule option in future C1 to C3 changes might consider including the screened HCAs (1,109 miles per above) along with MCAs, or "moderate consequence areas," as a subset of non-HCAs. PHMSA established MCAs as part of the Safety of Natural Gas Transmission Final Rule, which mandates that MCAs conduct the same data analysis requirements for assessments conducted as an HCA, and use similar assessment methods as an HCA. Given the proposed rule's option emphasis on similar and related integrated management practices and technologies, MCAs represent a subset of non-HCAs with a relatively high likelihood of qualifying for and using the proposed rule option, compared to other non-HCA segments. PHMSA's PRIA for the Safety of Natural Gas Transmission Final Rule estimates that there are approximately 11,860 Class 1 of piggable MCA miles. Combined with the 1,109 screened HCA miles, PHMSA estimates a total of 12,969 of potentially qualifying Class 1 miles, or about 5.5 percent of the 232,768 total Class 1 miles.

Where the former estimate of 63 percent is judged to be too broad as a screening approach, overstating the target population, PHMSA similarly views the latter estimate (5.5 percent) as uncertain, in this case understating the target population by being too narrow in including *only* HCA and MCA candidate mileage. PHMSA therefore follows a similar approach to the activity baseline, and relies on the midpoint (average) of these two bounding cases: 34 percent.

Exhibit 4-3 and Exhibit 4-4 summarize PHMSA's assumptions regarding operators' choice of compliance methods under the baseline and rule scenario for two scenarios.

Appendix D: Estimating Unit Costs for Compliance Methods

PHMSA presents unit costs for the Special Permit method and new compliance method together because many of their requirements and cost elements overlap and are nearly identical.

PHMSA outlined "threshold conditions" pipelines must meet to be considered for a Special Permit after a class location change in a 2004 Federal Register publication (FR 38948, Vol. 69, No. 124). The proposed rule method in § 192.618 incorporates most of these requirements. The new compliance method also requires pipeline operators to have operational remote control of mainline valves, or install automatic shut-off valves, a requirement that is not asked of Special Permit applicants.

This Appendix details PHMSA's methodology for estimating unit costs for requirements summarized previously in Section 4.2.2, Exhibit 4-5.

D.1 Integrity Management Program

For each pipeline segment changing class location, the operator incurs a one-time cost of incorporating the segment into their IMP. These costs apply to pipe segments being managed under a special permit or under § 192.610. Furthermore, the operator must include the segments changing class location in its IMP baseline assessment plan.

PHMSA assumes this action takes an operator 10 hours per segment to complete. To estimate this cost, PHMSA used the fully-loaded occupational rate $79.47 per hour for a mechanical engineer in the natural gas pipeline sector (also see Section D.21, Labor-Related Costs) to incorporate each segment into a written integrity management program. To convert labor costs to a "dollars per foot" basis, PHMSA divided the total labor cost for each segment by the average segment length of a pipe (1,392 ft.) to estimate the labor cost per foot. PHMSA presents a unit cost of $0.57 per foot in Exhibit D-1.

Exhibit D-1: Integrity Management Program Unit Costs ($2018)

Occupation	*Rate*	*Hours per Segment*	*Total Labor Cost*	*Avg. Segment Length (ft.)*	*Labor Cost ($ per ft.)*
Mechanical Engineer	$79.47	10	$794.68	1,392	$0.57

Segments changing from C1 to C3, located in HCAs, are already mandated to complete this requirement under § 192.907. As required by the Safety of Natural Gas Transmission Final Rule, operators in MCA locations will also complete this requirement. Therefore, this cost is not included for HCA and MCA segments managing C1 to C3 changes through special permit, in the baseline, and through special permit and the rule option in the proposed rule scenario. This cost is assigned to non-HCA and non-MCA segments changing from C1 to C3 and using either the special permit or rule option. Note that the analysis of total costs, including the allocation of costs to miles managed by option and for HCA, MCAs, and non-HCA/MCAs, is described in Section 4.3.

D.2 Close Interval Survey (Initial and Reassessment)

Each operator must perform a close interval survey (CIS) of pipeline segments applying for either a special permit following the requirements of § 192.618 along the entire length of the pipeline segment and remediate any areas of inadequate cathodic protection. Furthermore, operators are required to perform periodic CIS of the segments at the applicable reassessment interval(s) for "covered segments" in accordance with § 192.939, not to exceed a seven-year reassessment interval.

To estimate the cost of CIS, PHMSA used Gulf Interstate Engineering.[40] To estimate the cost of CIS, PHMSA used Gulf Interstate Engineering's estimate which assumed survey costs are independent of the pipeline size, across diameters ranging from 10 to 42 inches. The estimate includes the survey crew, equipment, and vehicles, but the survey analysis cost does not include any verification digs.[41] In addition, Gulf Interstate Engineering assumes that the surface over the pipeline is soil and the route is walkable and accessible. Exhibit D-2 presents the final value of $0.86 per foot that PHMSA used to estimate the cost of CIS.

Exhibit D-2: Close Interval Survey Unit Costs ($2018)

Segment Length (ft.)	*2,500*	*5,000*	*10,000*	*20,000*	*30,000*	*Average*
Total Cost (dollars per foot)	$1.83	$0.91	$0.79	$0.39	$0.37	$0.86

Source: Gulf Interstate Engineering 2017.

Segments located in HCA locations should have already completed this requirement as mandated in § 192.939. CIS is common part of External Corrosion Direct Assessment in IMPs for HCA locations. As required by the Safety of Natural Gas Transmission Final Rule, operators in MCA locations will also complete this requirement. Therefore, this cost is not included for HCA and MCA segments managing C1 to C3 changes through special permit, in the baseline, and through special permit and the rule option in the proposed rule scenario. This cost is assigned to non-HCA and non-MCA segments changing from C1 to C3 and using either the Special Permit or proposed option.

D.3 Coating Condition & Casings

PHMSA requires operators seeking a special permit to complete within one year a Direct Current Voltage Gradient (DCVG) survey or an Alternating Current Voltage Gradient (ACVG) survey of each segment to determine the pipeline coating conditions and remediate any integrity issues. Furthermore, an operator must identify all shorted casings within each special permit segment no later than six months after the grant of this special permit. PHMSA assumed each operator would perform either a DCVG or ACVG survey one time for each pipeline segment changing class location.

Like CIS, ACVG/DCVG survey costs are independent of the line size. Additionally, these estimates account for survey crew, equipment, vehicles, and survey analysis but do not include any verification digs. Exhibit D-3 presents the final value of $1.06 per foot that PHMSA used to estimate the cost of ACVG or DCVG analysis. that PHMSA used to estimate the cost of ACVG or DCVG analysis. Since this Special Permit condition goes beyond current requirements, PHMSA assumed these one-time costs were incremental to HCAs, MCAs, and all other pipeline consequence locations.

Exhibit D-3: ACVG/DCVG Unit Costs ($2018)

Segment Length (ft.)	*2,500*	*5,000*	*10,000*	*20,000*	*30,000*	*Average*
Total Cost (dollars per foot)	$2.23	$1.11	$0.99	$0.49	$0.47	$1.06

Source: Gulf Interstate Engineering 2017.

[40] Oak Ridge National Laboratory, *Pipeline Testing and Inspection Cost Estimates*, Gulf Interstate Engineering Project No. 1765, Document No. 1765-000-EBM-0001-00 (2017).

[41] A CIS would not require a verification dig. It measures whether the cathodic protection current is getting to the pipe. CIS equipment is calibrated without the need of a field verification dig. Digs would only be needed should the coating be detrimental to maintaining safety by not having sufficient cathodic protection current, which is a code requirement.

D.4 Stress Corrosion Cracking Direct Assessment

The Special Permit conditions require operators to evaluate their pipeline segments for stress corrosion cracking (SCC) with a pressure test, in-line inspection with a crack detection tool, or some other approved method along the entire length of the special permit inspection area no later than one year after of the grant of this special permit affordability. The proposed rule language for §192.618 does not require a Stress Corrosion Cracking Direct Assessment (SCCDA) explicitly, but lists additional maintenance requirements for cracked pipe. Pipelines operating as part of an existing IMP are already required to complete SCCDA under § 192.929. For pipelines located in other consequence locations (i.e. non-HCA/non-MCA), this is an incremental cost.

Direct assessment (DA), involves four distinct phases:

1. Pre-assessment data collection and analysis,
2. Indirect inspection by walking along the top of the pipeline, inducing an electrical charge or signal in the steel pipe, and measuring the resulting signal,
3. Excavation and direct examination of suspect locations identified by the indirect inspection, and
4. Post-assessment analysis of inspection and examination findings.

In the first phase, an operator identifies historical knowledge of the pipeline, including facilities information, operating history, and the results of prior aboveground indirect examinations and direct examinations of the pipe, to assess the integrity of the pipe. In the second phase, the operator uses the primary and complementary indirect examinations to detect coating defects. The operator uses the results to find coating faults (e.g., damaged pipeline coating). For example, based on pipeline history, the operator may use the survey results to determine which coating faults are most likely to correspond to the severely corroded areas. Those areas where the potential for severe corrosion is highest should receive excavation priority. The third phase requires excavations to expose the pipe surface for metal-loss measurements, estimated corrosion growth rates, and measurements of corrosion morphology estimated during indirect examination. The goal of these excavations is to collect enough information to characterize the corrosion defects that may be present on the pipeline segment being assessed and validate the indirect examination methods. The operator should then determine the severity of all corrosion defects at the excavated coating fault areas using ASME B31G or a similar method to determine the safe operating pressure at the location. The final phase sets re-inspection intervals, provides a validation check on the overall ECDA process, and provides performance measures for integrity management programs. The re-inspection interval is a function of the validation and repair activity.

There is a potential range of cost associated with each phase. Cost is largely dependent on location, since the high cost of DA in urban and suburban areas includes traffic control and excavation permitting. PHMSA used best-professional-judgment to estimate the cost of each phase (Exhibit D-4**)** and used the average estimate.[42] Unit costs of performing DA are relatively independent of the length of the assessment segment. PHMSA applied these unit costs to only pipes in non-MCA and non-HCA locations.

[42] PHMSA's estimate is based on the following assumed ranges for each phase (cost per mile): pre-assessment: $5,000 - $10,000; indirect inspection: $2,500 - $18,000; direct examination: $15,000 - $20,000; and post assessment: $5,000 - $10,000. The total cost per mile is assumed to therefore be in the range of $27,500 - $58,000.

Exhibit D-4: Estimated Unit Cost of Direct Assessment (($2018 per foot)			
	Low Estimate	*High Estimate*	*Average*
Pre-assessment	$0.95	$1.89	$1.42
Indirect inspection	$0.47	$3.41	$1.94
Direct Examination	$2.84	$3.79	$3.31
Post Assessment	$0.95	$1.89	$1.42
Total	**$5.21**	**$10.98**	**$8.10**

D.5 Reporting Pipe Coating & Remediation

Class change special permits require an operator to submit, DCVG, ACVG, CIS, and SCCDA findings, include remediation actions, in a written report to the PHMSA Regional Director. PHMSA believes this process takes a mechanical engineer two hours to complete. Using a Mechanical Engineer's labor rate and dividing total labor costs by average segment size, PHMSA estimates the final estimated cost of these segments equal $0.11 per foot (Exhibit D-5). This cost affects all pipes regardless of consequence location.

Exhibit D-5: Reporting Pipe Coating & Remediation ($2018)

Occupation	*Rate*	*Hours per Segment*	*Total Labor Cost*	*Avg. Segment Length (ft.)*	*Labor Cost ($ per foot)*
Mechanical Engineer	$79.47	2	$158.94	1,392	$0.11

D.6 Amend O&M Manual

Special Permit Condition 9 requires operators to amend applicable sections of its O&M manual(s) to require the CIS inspection and reassessment intervals of the pipeline name pipeline special permit segments at a frequency consistent with 49 CFR part 192, subpart O, but not to exceed a seven (7) year reassessment interval. PHMSA assumed this process would take 80 hours for a mechanical engineer to complete this procedural change per segment. This action is not required of the proposed § 192.618, therefore it is only considered in the baseline for special permit applications.

PHMSA assumed this action takes an operator 80 hours per segment to complete. To estimate this cost, PHMSA used the occupational rate ($60.13 dollars per hour) of a Mechanical Engineer from Section D.21 incorporating each segment into an operator's O&M manual. To convert the costs to a dollars-per-foot basis, PHMSA divided the total labor cost for each segment by the average segment length of a pipe to change class location. PHMSA presents the total unit cost of about $4.57 per foot in Exhibit D-6.

Exhibit D-6: O&M Manual Procedural Changes Unit Cost ($2018)

Occupation	*Rate*	*Hours per Segment*	*Total Labor Cost*	*Avg. Segment Length (ft.)*	*Labor Cost ($ per Foot)*
Mechanical Engineer	$79.47	80	$6,357.47	1,392	$4.57

Source: PHMSA's Best Professional Judgement

If the pipeline segment is located in an MCA or HCA, operators should already include these segments in their O&M manuals. Therefore, these costs would only be incremental for pipeline segments not located in MCA or HCA locations.

D.7 ILI Assessment and Reassessment

As mandated by Conditions 10 & 11 of a typical Special Permit, and PHMSA requires operators will conduct ILIs of their pipelines. The analysis includes two mandated types of ILIs: a high-resolution magnetic flux leakage (MFL) ILI, and Geometry/Deformation (Geometry) ILI. All estimates assume that no pipeline cleaning is required prior to ILI.

High-Resolution MFL ILI Costs

MFL ILI tools locate and record magnetic flux anomalies in pipelines. The recorded magnetic flux data provide an indication of metal loss in the pipe (Kishawy and Gabbar 2010). MFL costs presented here reflect a 50-mile interval (the distance between two compressor stations); and include costs associated with move-in, move-out, tool tracking, an analysis of tool results, and a gauge plate run preceding any intelligent pig. The costs assume that an intelligent pig train includes an MFL and geometry pigs, which are common in the industry. The estimate for each pig run includes allowance for operational support and tracking based on an assumed pig travel time of 12 hours.

PHMSA estimates per-foot unit costs for MFL – ILI in Exhibit D-7. The total cost data from divided by the length of a 50-mile segment (264,000 feet) ILI is typical completed in large mile increments. A pig is inserted at a launcher and removed at a receiver that may be 20, 50, or 100 miles down the pipeline. A 50-mile segment was used to estimate costs in Gulf Interstate Engineering, which is used by PHMSA to then estimate cost-per-foot. PHMSA then calculated an overall weighted average of $0.62 per foot for a MFL ILI based on the percent of pipes operating in each diameter size category. PHMSA used the distribution of the entire onshore transmission network since Part H of the Annual Report does not provide information to distinguish the diameter of pipes most likely to comply using this method.

Exhibit D-7: MFL ILI Costs (2018$ per foot)

Diameter (inches)	*Mobilization and Demobilization*	*HR-MFL ILI and Analysis*	*Total*	*Percent of All Pipes, by Diameter*	*Weighted Average Cost*
10	$0.10	$0.50	$0.60	31%	
16	$0.10	$0.50	$0.60	22%	
24	$0.10	$0.51	$0.61	16%	$0.62
36	$0.10	$0.57	$0.67	27%	
42	$0.10	$0.57	$0.67	4%	

Source: Gulf Interstate Engineering 2017 costs and PHMSA 2017.

Geometry/Deformation ILI Costs

The purpose of Geometry ILI tools is to gather information about the physical shape and condition of a pipeline, primarily to find outside force damage or dents. These tools are also capable of detecting and locating mainline valves, fittings, and other appurtenances (Kishawy and Gabbar 2010). The Geometry ILI costs presented below include a caliper pig run (geometry tool) and an analysis of tool results for a 50-mile interval. This estimate includes costs associated with move-in, move-out, tool tracking, and a gauge plate run preceding any intelligent pig. Each pig run includes allowance for operational support and tracking based on an assumed pig travel time of 12 hours.

PHMSA estimates per-foot costs, Exhibit D-8, based on the total cost for each diameter divided by the length of a 50-mile segment (264,000 feet). (264,000 feet). PHMSA then calculated a weighted average of $0.24 per foot for a Geometry ILI based on the percentage distribution of all onshore transmission pipelines, by diameter.

Exhibit D-8: Geometry ILI Unit Costs (2018$ per foot)

Diameter (inches)	*Mobilization and Demobilization*	*Geometry ILI and Analysis*	*Total*	*Percent of All Pipes, by Diameter*	*Weighted Average Cost*
10	$0.05	$0.18	$0.23	31%	
16	$0.05	$0.18	$0.23	22%	
24	$0.05	$0.19	$0.24	16%	$0.24
36	$0.05	$0.20	$0.25	27%	
42	$0.05	$0.20	$0.25	4%	

Source: Gulf Interstate Engineering 2017 costs and PHMSA 2017.

D.8 Damage Prevention Best Practices

Operators must incorporate the applicable best practices of the Common Ground Alliance into its damage prevention program within the special permit inspection areas. PHMSA does not expect this requirement to require a lot of effort from operators. The current CFR requires all of these practices.

PHMSA assumes this action takes an operator 2 hours per segment to complete. To estimate this cost, PHMSA uses the occupational rate for a Mechanical Engineer, ensuring each segment follows damage prevention best practices. To convert the costs to a dollars-per-foot basis PHMSA divided the total labor cost for each segment by the average segment length of a pipe to change class location as presented in Exhibit D-1. PHMSA presents the total unit cost of about $0.11 per foot in Exhibit D-9. This one-time cost is required for any special permit applicants regardless of the pipes location in an HCA, MCA, or other location.

Exhibit D-9: Damage Prevention Best Practices Unit Costs ($2018)

Occupation	*Rate*	*Hours*	*Total Labor Cost*	*Avg. Segment Length (ft.)*	*Labor Cost ($ per ft.)*
Mechanical Engineer	$79.47	2.00	$158.94	1,392	$0.11

Source: PHMSA Best Professional Judgement

D.9 Field Activity Notice to PHMSA

PHMSA requires operators to give a minimum of 14 days advance notice to the Regional Director enabling PHMSA to observe the excavations relating to coating conditions surveys, SCCDA, field coating maintenance, anomaly evaluation and repair, girl weld maintenance, casing maintenance, and pipe seam evaluation of field activities in the special permit inspection area. This notice is traditionally either a phone call, e-mail, or letter to a PHMSA regional director and in most cases filed early in the year, prior to the work season.

PHMSA assumes this action takes an operator about 10 hours per segment to complete. To estimate this cost, PHMSA uses the occupational rate of a Mechanical Engineer. To convert the costs to a dollars-per-foot basis PHMSA divided the total labor cost for each segment by the average segment length of a pipe as presented in Exhibit D-1. PHMSA presents the total unit cost of about $0.57 per foot in Exhibit D-10. This one-time cost is required for any special permit holders regardless of the pipes location in an HCA, MCA, or other location.

Exhibit D-10: Field Activity Notice to PHMSA Unit Costs ($2018)

Occupation	*Rate*	*Hours*	*Total Labor Cost*	*Avg. Class Change Segment Length (ft.)*	*Labor Cost ($ per ft.)*
Mechanical Engineer	$79.47	10.00	$794.68	1,392	$0.57

Source: PHMSA Best Professional Judgement

D.10 Annual Report to PHMSA

Within three months following the grant of this special permit and annually thereafter for the duration of the special permit, an operator must submit an annual report on the affected pipeline segments to PHMSA. Exhibit D-11 lists PHMSA's estimate of the steps, time, and costs for a special permit holder to prepare an annual report on their special permit pipe segments. PHMSA estimates that these reports take an estimated 100 hours and about $9,313 to complete per annual report for the average 1392 foot segment, or $6.69 per foot.

Exhibit D-11: Annual Report Process and Cost ($2018)

Action	***Hours***	***Occupation***	***Occupational Code***	***Hourly Labor Wage***	***Total Cost***
The operator must describe the economic benefits of the special permit including both the costs avoided from not replacing the pipe and the added costs of the inspection program. Subsequent annual reports should address any changes to these economic benefits.	15	Financial Manager	11-3031	$109	$1,635

Action	Hours	Occupation	Occupational Code	Hourly Labor Wage	Total Cost
The operator must describe how the public benefits from energy availability. This should address the benefits of avoided disruptions as a consequence of pipe replacement and the benefits of maintaining system capacity. Subsequent reports must indicate any changes to this initial assessment.	15	Financial Manager	11-3031	$109	$1,635
The operator must describe the number of new residences, other structures intended for human occupancy and public gathering areas built within the special permit inspection areas.	10	Mechanical Engineer	17-2141	$60	$600
The operator must describe any new integrity threats identified during the	10	Mechanical Engineer	`11-3031	$113.20	$1,132

Action	Hours	Occupation	Occupational Code	Hourly Labor Wage	Total Cost
previous year and the results of any ILI or direct assessments performed during the previous year in the special permit inspection areas.					
The operator must describe any reportable incident or any leak normally indicated on the DOT Annual Report, and all repairs on the pipeline that occurred during the previous year in the special permit inspection areas.	10	Mechanical Engineer	`11-3031	$113.20	$1,132
The operator must describe any on-going damage prevention initiatives affecting the special permit inspection areas and a discussion of the success of the initiatives.	10	Mechanical Engineer	17-2141	$79.47	$795
The operator must describe annual	10	Mechanical Engineer	17-2141	$79.47	$795

Action	Hours	Occupation	Occupational Code	Hourly Labor Wage	Total Cost
data integration information, as required in Condition 24 (e) - Data Integration.					
The operator must describe any mergers, acquisitions, transfer of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.	10	Lawyer	17-2141	$79.47	$795
Senior Manager(s) review Annual Report before submission to PHMSA.	5	General and Operations Managers	17-2141	$79.47	$397
Operator's legal team review Annual Report before submission to PHMSA	5	Lawyer	17-2141	$79.47	$397
Total	**100**	**na**	**na**	**na**	**$9, 313**

Total may not sum due to rounding.

D.11 Cathodic Protection Test Station Installation & Remediation

The special permit and proposed rule requirement § 192.618 mandates at least one cathodic protection pipe-to-soil test station must be located within each HCA with a maximum spacing between test stations of one-half mile within an HCA. Cathodic protection test stations are fairly common so PHMSA assumed operators would need to add a test station to every other pipeline segment.

The cost of the installation of a cathodic protection test station (CTS) can vary depending on surface conditions (paved or soil), depth of pipeline, access challenges, local environmental permit requirements, allowable work hours, and traffic controls. A vendor estimate provided by Mears suggested in rural areas CTS installation can range from $3,000 to $8,000 per installation.[43] These Class 1 changes tend to be relatively more rural, versus in a dense urban area. PHMSA uses the average value of this range and assumes each installation costs $5,500 dollars. PHMSA applied this cost to pipe segments in all consequence locations.

D.12 Interference Currents Control

PHMSA requires that operators must address induced alternating current from parallel electric transmission lines and other interference issues in the special permit inspection areas that may affect the pipeline. The proposed rule option similarly mandates that an operator changing the class location of a pipeline segment must conduct an interference survey to address induced alternating current from parallel electric transmission lines and other interference issues within one year.

Operators only conduct these surveys if their pipeline is near power lines but to ensure costs are not underestimated, PHMSA assumed all operators conduct this survey. The procedures and equipment required for an Interference Current Control survey is similar to an ACVG or CIS survey. PHMSA took the average these two survey costs, which is $0.96 per foot. PHMSA applied this cost to pipe segments in all consequence locations.

D.13 Anomaly Evaluation and Repair

Special Permit Condition 20 requires operators to account for ILI tool tolerance and corrosion growth rates in scheduled response times, repairs, and then document and justify the values used. In addition, special permits require operators to investigate, evaluate, and repair anomalies located on special permit segments or inspection area in accordance with 49 CFR §§ 192.485 and 192.933.

The proposed rule in § 192.411(e)(3) to (e)(5) list similar anomaly evaluation and repair criteria, in addition to specific requirements for operators evaluating immediate, one-year, and monitored conditions.

PHMSA does not mandate operators report repair data with the detail necessary to estimate when specific anomaly evaluation or repair requirements are addressed for gas transmission pipelines changing from C1 to C3 segments under a special permit or § 192.618. For example, PHMSA does not know the frequency in which operators may discover a monitored condition pipe wall thickness loss less than or equal to 40 percent compared to other wall thickness thresholds.

However, PHMSA does require operators in their Annual Report, Part F, to report total mileage inspected each calendar year and the total number of conditions repaired in calendar year both inside and outside HCA segments. Using this rate of discovery, PHMSA can measure the impacts on anomaly evaluation and repair costs of including more pipeline in an operator's IMP. When 63 miles of pipeline switch from pipe replacement to the proposed rule option, they will be required to be inspected more often. According to Annual Report Part F data, in 2017, PHMSA inspected 53,315 miles as part of IMPs and repaired 3,934 anomalies. Therefore, PHMSA estimates operators identify 0.074 repairs per mile of HCA segment annually. Since all pipe segments who comply via special permit or § 192.618 are required to be operated as an HCA location, PHMSA assumed that all miles using either the Special Permit or proposed rule option discover repairs at this rate.

[43] Gulf Interstate Engineering 2017.

As part of gas transmission incident reports filed with PHMSA operators must identify, in Part D, Question 7.b, the estimated cost of operator's property damage and repairs after an incident.[44] Reported damages include physical damage to the property of the operator and the cost of repairs to company facilities.[45] Additionally, repair costs include expenses to safely restore property to its predefined level of service and may include the cost to access, excavate, and repair the pipeline using methods, materials, and labor necessary to re-establish operations at a predetermined level.[46] These damages exclude the cost of any gas lost, litigation, and other legal expenses related to the incident.

PHMSA screened the incident data to collect only incidents that occurred on an onshore, steel pipeline and caused by corrosion or a material failure of the pipe or weld. As presented in Exhibit D-12, from the available incident data PHMSA identified 13 incidents that occurred in HCA locations and 212 in non-HCA locations from 2010 to January 2019. PHMSA found the distribution of repair-related costs to be statistically indistinguishable between HCA and non-HCA with a median of $120,000 for HCA incidents and $119,062 for non-HCA incidents. PHMSA pooled all of the incidents to estimate an average repair-related cost of $584,340 per incident. When operators discover a condition, PHMSA estimates this as a one-time cost for pipelines operating in MCA and other non-HCA locations. Pipelines operating in HCA locations should already inspect for anomalies and make similar repairs.

Exhibit D-12: Operator Repairs Costs by Consequence Location ($2018)

Location	*No. of Incidents*	*Operator Repair Costs (per incident)* Median	*Operator Repair Costs (per incident)* *Average*
HCA	13	$120,000	$304,713
non-HCA	212	$119,062	$601,487
Both	225	$120,000	$584,340

Source: Incident Report Form F7100.2 Part D question 7.b. Note: Includes HCA and non-HCA incidents that occurred in steel pipe, onshore locations, and caused by corrosion or material failure of the pipe or weld.

D.14 Girth Welds Records

Special Permit Condition 21 requires operators to provide PHMSA records that demonstrate the pipeline segments' girth welds were non-destructively tested at the time of construction in accordance with federal pipeline safety regulations. However, PHMSA does not propose the same requirement as part of § 192.610. Instead, PHMSA mandates that pipe with cracking in the pipe body, seam, or girth welds in or within 5 miles of a Class 1 pipeline segment cannot be changed to a Class 3 segment under the proposed. For this requirement PHMSA assumed operators would incur some recordkeeping and filing costs to prepare the appropriate documents for PHMSA when applying for a special permit.

PHMSA assumes this action takes an operator 5 hours per segment to complete. To estimate this cost, PHMSA used the occupational rate fora Mechanical Engineer organizing girth weld records for each covered segment. To convert the labor costs to a dollars-per-foot basis, PHMSA divided the total labor cost for each segment, by the average segment length of a pipe (1,392 ft.) to estimate the labor cost per foot of this activity. PHMSA presents the total unit cost of about $0.29 per foot in Exhibit D-13.

[44] PHMSA Form F7100.2 (rev 10-2014) Incident Report –Natural and Other Gas Transmission and Gathering Pipeline Systems.

[45] Such as the estimated installed or replacement value of the damaged pipe, coating, component, materials, or equipment.

[46] These costs may include the cost of repair sleeves or clamps, re-routing of piping, or the removal from service of an appurtenance or pipeline component.

Exhibit D-13: Integrity Management Program Unit Costs ($2018)

Occupation	*Rate*	*Hours*	*Total Labor Cost*	*Avg. Segment Length (ft.)*	*Labor Cost ($ per ft.)*
Mechanical Engineer	$79.47	5	$397.34	1,392	$0.29

Source: PHMSA Best Professional Judgement

A class 1 segment upgrading to class 3 segment located in HCA locations complete are mandated to complete this requirement already by § 192.907. As required by the Safety of Natural Gas Transmission Final Rule operators in MCA locations will also complete this requirement. Therefore, this cost primarily effects pipe segments located in non-MCA or non-HCA locations.

D.15 Depth of Cover Survey

PHMSA's proposed rule requires under operators to conduct a depth of cover survey in accordance with § 192.327 for pipe segments changing class location. In addition, Condition 24(a) of most special permits historically requires a depth of cover survey within six months.

PHMSA assumes an operator would conduct this survey in conjunction with another survey (i.e. ACVG, DCVG, or CIS) required by the special permit or proposed rule. Therefore, to account for extra Depth of Cover Survey costs PHMSA assumed each segment would require an additional 24 hours of a Mechanical Engineer's time to implement the survey and process the results.

To estimate this cost, PHMSA used the occupational rate for a Mechanical Engineer incorporating each segment into a written integrity management program. To convert the labor costs to a dollars-per-foot basis, PHMSA divided the total labor cost for each segment, by the average segment length of a pipe (1,392 ft.) to estimate the labor cost per foot of this activity. PHMSA presents the total unit cost of about $1. 37 per foot in Exhibit D-14.

Exhibit D-14: Depth of Cover Survey Unit Costs ($2018)

Occupation	*Rate*	*Hours*	*Total Labor Cost*	*Avg. Segment Length (ft.)*	*Labor Cost ($ per ft.)*
Mechanical Engineer	$79.47	24	$1,907.24	1,392	$1.37

Source: PHMSA Best Professional Judgement

D.16 Line-of-Sight Markers & Pipe Warning Tape

According to the Special Permit requirements and proposed rule option operators must install and maintain line-of-sight markings and pipeline warning tape along the special permit segment. Using information from vendor websites, PHMSA assumes line-of-sight markers costs an estimate $21.15 per marker.[47] Current regulations and best practices require pipeline markers for buried transmission lines placed and maintained as close as practical over each buried main and transmission line[48] and in high activity areas markers should be places to that two markers are visible in any one location along the pipeline.[49] Therefore, PHMSA assumed operators would need one marker for about every 50 feet on

[47] For example, Berntsen International's LineMarker Round Top range in price from $3.70 per marker to $38.20 as of January 10, 2019, See https://www.berntsen.com/Utilities/Carsonite-Pipeline-Markers/LineMarker-Round-Top.

[48] § 192.707.

[49] Vulcan, Inc. Vulcan Safety Short- Pipeline Marker Regulations. Accessed January 10, 2019. https://www.youtube.com/watch?v=EliJJI30iPs.

average. This means an operator needs about 106 markers to cover one mile of pipeline. Therefore, an operator applying for a special permit needs to budget $2,242 per mile ($0.42 per foot) for line markers.

Similar vendor websites offer a variety of types and sizes of pipeline warning tape. PHMSA assumed pipeline warning tape costs about $273.20 for a role of 1000 feet (or $0.27 per foot).[50] Assuming an operator needs two rolls of warning tape, one for each side of the pipeline, the total cost for pipeline warning tape would be $0.55 dollars per foot.

D.17 Data Integration, Documentation & Records

Condition 24(e) of the standard class location special permit requirements mandates operators to integrate their data of special permit condition findings and remediation for the special permit inspection areas. In special permits PHMSA mandates pipeline data integration must include information such as pipe material characteristics; MAOP; class location and HCA boundaries; hydrostatic test pressure records; ILI, CIS, depth of cove, pipe coating, interference survey results; and SCCDA findings.

Additionally, operators are required to maintain the following records for each special permit segment changing class location. This documentation must include proof the segment has received a 49 CFR § 192.505, Subpart J, hydrostatic test and documentation of mechanical and chemical properties including pipe toughness. The proposed requirements have the same documentation requirements that state for the life of the C1 to C3 location segment a record of the pipeline assessments, surveys, remediation, maintenance, and analyses, but not list the same data integration requirements.

PHMSA assumes each operator would spend about $35,000 per pipe segment to integrate pipeline records when using a special permit to waive the requirements of § 192.611. In addition, PHMSA estimates the documentation and records requirements an operator an additional 6 hours to complete. Exhibit D-15 shows PHMSA estimate of documentation and record requirement at an estimated $0.34 dollars per foot.

Exhibit D-15: Documentation and Recordkeeping Labor Cost ($2018)

Occupation	*Rate*	*Hours*	*Total Labor Cost*	*Average Class Change Segment Length (ft.)*	*Labor Cost ($ per foot)*
Mechanical Engineer	$79.47	6	$476.81	1,392	$0.34

Source: PHMSA Best Professional Judgement

D.18 Right-of-Way Patrols & Leakage Surveys

Special Permit Condition 24(d) requires operators perform monthly right-of-way (RoW) patrols of the permitted segments each calendar year. In addition, PHMSA proposes in a monthly RoW patrols that meet § 192.705 standards in addition to monthly leakage surveys that meet § 192.706. PHMSA assumes operators would as part of standard procedure conduct leakage surveys in conjunction with their right-of-way patrol. Even though RoW patrols are already a fairly common industry practice, to overestimate cost, PHMSA assumed operators would conduct 12 incremental RoW patrols annually for each pipe segment changing from a C1 to C3 location.

[50] Seton Inc., https://www.seton.com/detectable-underground-warning-tape-caution-buried-pipeline-below-sp364.html#85512 Accessed January 10, 2019.

PHMSA assumes that a RoW patrol and leakage survey require labor and material costs that are similar in character and magnitude to a CIS. In addition, a CIS likely requires more equipment than a simple leakage survey so this proxy may overstate costs. Gulf Interstate Engineering's estimates included the survey crew, equipment, vehicles, and survey analysis, but excluded verification digs. Furthermore, Gulf Interstate Engineering assumed a buried pipeline and a walkable, accessible route. The labor costs assume two Mechanical Engineers survey pipe are a rate of one mile per hour, working 8 hours per day. PHMSA estimates that this process costs operators $0.88 per foot to implement (Exhibit D-16).

RoW patrols and leakage surveys are a process that occurs regularly in all consequence location. To be conservative with our estimate, PHMSA assumed operators in all consequence locations add additional surveys to their pipeline maintenance activities.

Exhibit D-16: Estimated Right-of-Way Patrol and Leakage Survey Costs ($2018)

Cost	*Value*	*Unit*	*Notes & Assumptions*
Additional Labor Costs	$0.03	dollars per foot	Two engineers, working 8 hour days, surveying pipe at 1 mph.
Close Interval Survey Costs	$0.86	dollars per foot	Required equipment and procedures is similar to CIS.
Total Cost	$0.89	dollars per foot	Labor + CIS

Source: PHMSA Best Professional Judgement and Gulf Interstate Engineering 2017

D.19 Remote Control Valves

Exhibit D-17 presents the incremental cost of equipping an existing actuated valve to operate as a Remote Control Valve or Automatic Shut-off Valve. An actuated valve is already motorized or has some other equivalent means of mechanized operation. The upgrade cost is therefore the incremental cost of communications equipment and other systems required to enable remote operation of the actuator. Communications equipment is needed to operate the actuator remotely from a control center. Additionally, each valve site likely needs a remote terminal unit to control the actuator, backup power supplies, and possibly an above ground or underground structure to house the additional equipment. Finally, the operator would need to equip the covered pipeline segments with pressure monitoring equipment if it is not already equipped to detect ruptures. Some new and replaced valves may already have some of these components installed and therefore costs may be slightly overstated. Specifically, PHMSA expects that most valve sites would not require new structures to house the control equipment.

Exhibit D-17: Unit Cost to Equip Actuated Valve for Remote or Automatic Operation (2018 $ per installation)

Component	*Unit Cost[1]*	*Annualized Cost[2]*
Communications equipment and installation	$30,000	$3,590
RTU, batteries, and building	$12,000	$1,030
Pressure monitoring equipment	$2,500	$299
Total	$44,500	$4,918

RTU = remote terminal unit

1. The estimated cost for pressure monitoring equipment is PHMSA best professional judgement. All other estimates for unit cost are derived from information provided by a vendor.
2. Annualized over useful life (13 years for communications component and pressure monitoring equipment; 25 years for the RTU, batteries, and building) using a 7% discount rate. Calculated using the Microsoft Excel PMT function, which returns the payment amount for every period (year) on an amount using constant payments and a constant interest rate [e.g., for communications equipment and installation, the arguments for the PMT function are =PMT (7%, 13, $30,000); the result is $3,590].

D.20 PHMSA Staff Special Permit Application Review

The National Environmental Policy Act (NEPA), 42 U.S.C. 4321 et seq., Council on Environmental Quality regulations, 40 CFR 1500-1508, and U.S. Department of Transportation Order 5610.1C require PHMSA to analyze any proposed special permit 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 affect the likelihood or consequence of a pipeline failure as compared to the operation of the pipeline in full compliance with the Pipeline Safety Regulations. In addition, PHMSA staff may conduct other internal analysis, prepare legal documents, or draft letters to communicate with special permit applicants. PHMSA estimates that it spends 70 hours on a NEPA analysis per segment and an additional 40 hours of labor on additional documents and communications per pipeline segment. Using the corresponding labor rates from Section D.21, PHMSA estimates the total cost for the agency to prepare the appropriate documents to support a special permit costs the agency about $7.00 per foot or $9,746 dollars per segment. These costs affect all miles managed by special permit regardless of consequence location.

Exhibit D-18: PHMSA Staff Support Special Permit Costs ($2018)

Task	Lead	Average Wage	Hours	Total Labor Cost	Total Labor Cost per Segment ($ per foot)
NEPA Assessments					
Preparing NEPA Analysis	Environmental Scientists and Specialists, Including Health	$76.3	50	$3,817	$2.74
Manager Review of Document	General & Operations Managers	$95.1	10	$951	$0.68
Legal Review of NEPA Analysis	Lawyers	$102.6	10	$1,026	$0.74
Total NEPA Assessment Cost			70	$5,794	$4.16
Other Special Permit Supporting Documents					
Manager review and preparation of documents	General & Operations Managers	$95.1	20	$1,901	$1.37
Legal review	Lawyers	$102.6	20	$2,051	$1.47
Total Other Documents Cost			40	$3,952	$2.84
Total Staff Costs				**$9,746**	**$7.00**

D.21 Labor-Related Costs

As indicated in Sections D.1 to D.20 above, PHMSA uses industry- and occupation-specific labor rates to quantify operators' labor costs associated with tests, procedures, and record upkeep anticipated under the proposed rule, and that are independent from the unit costs for compliance technologies described in previous sections.

Exhibit D-19 presents mean hourly wages from the Bureau of Labor Statistics (BLS) for occupational categories that support the associated labor cost estimates. PHMSA included labor costs for four occupations in the pipeline transportation industry (NAICS 486200): Mechanical Engineer, Financial Manager, Lawyer, and General and Operations Manager.

Exhibit D-19: Labor Costs in Pipeline Transportation of Natural Gas ($2018)

Occupation Code	Occupation	Mean Hourly Wage ($/hr.)	Total Hourly Labor Cost ($/hr.)
17-2141	Mechanical Engineer	$55.31	$79.47
11-3031	Financial Manager	$78.79	$113.20
23-1011	Lawyer	$88.26	$126.81
11-1021	General and Operations Managers	$56.13	$80.65

Source: Bureau of Labor Statistics Occupational Employment Statistics (U.S. Bureau of Labor Statistics 2018) and Employer Cost of Employee Compensation (U.S. Bureau of Labor Statistics 2018). Note: Mean hourly wage plus mean benefits (wages composed 68.2 percent of total labor cost).

PHMSA uses government-specific labor rates to quantify the time required for PHMSA to process each special permit application, renewal, or review. PHMSA staff draft letters, review applications, and prepare Environmental Impact Assessments (EIA) or Finding of No Significant Impact (FONSI) analyses to process each special permit applications. PHMSA uses labor costs for three occupations (Environmental Scientists and Specialists, Lawyer, and General and Operations Manager) from the Federal Executive Branch (NAICS 999100). Exhibit D-20 lists each occupation, occupational code, mean hourly wage, and hourly labor costs used to quantify labor costs.

Exhibit D-20: Labor Costs for Federal Government ($2018)

Occupation Code	Occupation	Mean Hourly Wage ($/hr.)	Total Hourly Labor Cost ($/hr.)
19-2041	Environmental Scientists and Specialists, Including Health	$50.39	$76.35
11-1021	General and Operations Managers	$62.74	$95.06
23-1011	Lawyers	$67.69	$102.56