Regulatory Impact Assessment

Final Rule—Pipeline Safety: Safety Standards for Increasing the Maximum Allowable Operating Pressure for Natural Gas Transmission Pipelines

[Docket No. PHMSA-05-23447]

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Office of Pipeline Safety
***Pipeline and Hazardous Materials Safety Administration* (PHMSA)**
U.S. Department of Transportation (DOT)

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EXECUTIVE SUMMARY

The Pipeline and Hazardous Materials Safety Administration (PHMSA) is making changes to the Federal pipeline safety regulations in 49 CFR Part 192, which cover the transportation of natural gas by pipeline. Specifically, PHMSA is allowing natural gas transmission pipeline operators to raise the maximum allowable operating pressure (MAOP) for certain pipelines (1) constructed of steel pipe manufactured using modern steel chemistry and rolling practices and standards, and (2) inspected and tested to more rigorous standards.

The regulation supports the Secretary of Transportation's priorities by improving performance and harnessing 21st- Century technologies. Not only does increasing operating pressure ease supply constraints by boosting pipeline capacity, but it also enhances pipeline efficiency. This enhanced performance is made possible by technological advances in metallurgy and pipe manufacture, as well as by improved pipeline lifecycle management practices. Pipelines built with improved steel pipe and operated in compliance with improved lifecycle management practices can operate safely at higher internal pressures. Since incipient pipeline flaws can occur during pipe manufacture or installation, the technological advances decrease the risk of these flaws resulting in pipe failure over time due to the operating pressure. Furthermore, improved lifecycle management practices, which include rigorous testing, allow operators to detect flaws well before failure. Because revised regulations allowing increased capacity encourage the use of newer pipeline materials and associated safety standards, the result should have a net positive effect on overall pipeline safety.

An analysis of the costs and benefits discounted at both 3 percent and 7 percent over a 20 year period demonstrates that there are significant net benefits. The exhibits below illustrate the calculations.

PRESENT VALUE OF THE BENEFITS OF THE RULE CALCULATED OVER 20 YEARS
($Million)

Benefit Items	Annual Benefits	Present Value at 3% Discount	Present Value at 7% Discount
Reduced Fuel Costs Savings	49.0	729	519
Reduced Capital Expenditures	54.6	812	578
Total Benefits	103.6	1,541	1,097

PRESENT VALUE OF THE COSTS OF THE RULE CALCULATED OVER 20 YEARS
($Million)

Cost Item	Present Value at 3% Discount	Present Value at 7% Discount
Baseline Internal Inspections	**28.3**	**27.2**
Additional Internal Inspections	29.0	17.3
Anomaly Repairs	3.0	2.2
Remotely Controlled Valves	11.6	9.0
Threat Identification and Evaluations	.6	.5
Patrolling	166.4	108.6
Total Costs	238.8	164.7

NET BENEFITS OF THE RULE
($ Million)

Discount rate	Present Value of the Benefits Calculated Over 20 Years	Present Value of the Costs Calculated over 20 Years	Net benefits
3%	1,541	239	1,302
7%	1,098	165	933

These analyses find that the rule is not expected to adversely affect the economy nor the environment. The analyses also find that, for those costs and benefits that can be quantified, the present value of net benefits is expected to be between $933 million and $1.3 billion. The undiscounted monetary costs of the rule are expected to average about $16.6 million per year over a 20-year period. The benefits resulting from the rule are estimated to be $103.6 million per year. The rule is expected to be an economically significant regulatory action within the meaning of Section 3(f)(1) of Executive Order 12866, due to the expected benefits of the rule which exceed the annual $100 million threshold for economic significance.

PHMSA has also determined, as required by the Regulatory Flexibility Act, that the rule would not have a significant economic impact on a substantial number of small entities in the United States. The rule mandates no action by gas transmission pipeline operators. Rather, it provides those operators with the option of using an alternative MAOP in certain circumstances, when certain conditions can be met. Additionally, PHMSA determined that the rule would not impose annual expenditures on State, local, or tribal governments or the private sector in excess of $132 million, and thus does not require an Unfunded Mandates Act analysis.

1. INTRODUCTION

The Pipeline and Hazardous Materials Safety Administration (PHMSA) of the U.S. Department of Transportation (DOT) is requiring changes to the Federal pipeline safety regulations in 49 CFR Part 192, which cover the transportation of natural gas by pipeline. Specifically, the regulation allows natural gas transmission pipeline operators to raise the maximum allowable operating pressure (MAOP) for certain pipelines (1) constructed of steel pipe manufactured using modern steel chemistry and rolling practices and standards, and (2) inspected and tested to more rigorous standards.

This report examines the benefits and costs of the regulatory changes. Additionally, the report includes the analysis required by the Regulatory Flexibility Act.

2. BACKGROUND

Gas transmission pipelines in the United States use steel pipe almost exclusively.[1] Under Federal pipeline safety regulations, steel transmission pipelines must use a MAOP that is below the specified minimum yield strength (SMYS) of the steel pipe. Each pipeline class, based on population density, ranging from Class 1 (undeveloped, rural land) through Class 4 (densely populated urban areas) has a different MAOP, which are currently as follows:

- Class 1: 72% of SMYS
- Class 2: 60% of SMYS
- Class 3: 50% of SMYS
- Class 4: 40% of SMYS.

The estimated percentages of transmission mileage in these four class locations are:

- Class 1: 80%[2] to 90%[3] of mileage
- Class 2: 5%[4] to 10%[5] of mileage
- Class 3: Less than 5%[6] to 10%[7] of mileage
- Class 4: Approximately 0.5% of mileage.[8]

When Federal regulations were adopted in 1970, 72 percent of SMYS was selected as the upper MAOP limit to ensure conservative safety margins. The manufactured quality of

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[1] Howard J. Murphy, Jr., Energy Experts International, "Reconsideration of Maximum Allowable Operating Pressure: Costs and Benefits – A Macroeconomic View," PHMSA-2006-23447-35.
[2] Ibid..
[3] Richard B. Kuprewicz, Accufacts Inc., "Increasing MAOP on U.S. Gas Transmission Pipelines," a paper prepared for the Pipeline Safety Trust, PHMSA-2006-23447-50.
[4] Ibid.
[5] Howard J. Murphy, Jr., Op. Cit.
[6] Richard B. Kuprewicz, Op. Cit.
[7] Howard J. Murphy, Jr., Op. Cit.
[8] Richard B. Kuprewicz, Or. Cit.

steel pipe at the time necessitated the conservative safety margins.[9] Since then, manufacturers have dramatically improved the quality of steel pipe. Additionally, pipeline construction practices and operation and maintenance (O&M) procedures of pipeline operators have improved. In response to the material, construction, and O&M advances, several nations, including Canada and the United Kingdom, have allowed pipelines to operate up to 80 percent of SMYS.[10] A few nations, including Japan and Germany, mandate a MAOP lower than 72 percent of SMYS.[11]

In 1970, Federal regulators allowed pipelines that had operated successfully for many years at a stress level greater than 72 percent of SMYS to continue to operate at the higher stress level. Currently, approximately five thousand miles of gas transmission pipelines in the U.S. are operating at a stress level that is greater than 72 percent of SMYS because of grandfathering.[12] Operators desiring a MAOP greater than 72 percent of SMYS may apply to PHMSA for waivers (i.e., special permits). When evaluating waiver applications, the key consideration for PHMSA is whether the pipelines can operate at higher stress levels without compromising safety.

Beginning in 2006, PHMSA evaluated requests for special permits from three companies seeking to operate natural gas transmission pipelines at higher pressures than currently allowed by regulation. Those requests were made by:

- Alliance Pipeline L.P.[13]
- Maritimes & Northeast Pipeline, L.L.C.[14]
- Rockies Express Pipeline L.L.C.[15]

The requests were for proposed and existing pipelines, and all requested permission to operate at 80% of SMYS in the Class 1 locations. Some requests also included increases in the MAOP for other class locations.

PHMSA afforded the public an opportunity to provide comments on each special permit request and received favorable comments from both industry respondents and the public. Additionally, PHMSA briefed its technical advisory committees, held a public meeting, and brought stakeholders into the development of permitting criteria. PHMSA received supportive comments at these meetings.

PHMSA granted all three requested special permits. In granting them, PHMSA required the operators to demonstrate compliance with certain design specifications and imposed additional safety standards.

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[9] Joy O. Kadner, PHMSA, "Reconsideration of Maximum Allowable Operating Pressures for Natural Gas Pipelines, PHMSA-2006-23447-46.
[10] Ibid.
[11] Howard J. Murphy, Jr., Energy Experts International, "Reconsideration of Maximum Allowable Operating Pressure: Costs and Benefits – A Macroeconomic View," PHMSA-2006-23447-35.
[12] Richard B. Kuprewicz, Op.cit.
[13] See DOT Docket PHMSA-2006-23387.
[14] Ibid.
[15] Ibid.

3. STATEMENT OF THE PROBLEM

The rule for permitting a greater maximum allowable operating pressure supports the Secretary of Transportation's priorities by improving performance and harnessing 21st-Century technologies. Increasing operating pressure can ease supply constraints by boosting pipeline capacity by as much as 10 percent. Increasing capacity also enhances pipeline efficiency. This enhanced performance is made possible by technological advances in metallurgy and pipe manufacture, as well as by improved pipeline lifecycle management practices. Pipelines built with improved steel pipe and operated in compliance with improved lifecycle management practices can operate safely at higher internal pressures. Since incipient pipeline flaws can occur during pipe manufacture or installation, the technological advances decrease the risk of these flaws resulting in pipe failure over time due to the operating pressure. Furthermore, improved lifecycle management practices, which include rigorous testing, allow operators to detect flaws well before failure. Because revised regulations allowing increased capacity encourage the use of newer pipeline materials and associated safety standards, the result should have a net positive effect on overall pipeline safety.

PHMSA's rulemaking grows out of the Agency's examination of the safety issues in allowing existing or proposed pipeline to operate at higher pressure. From a policy perspective, the experience with previously granted special permits has been very positive. One of the successful operators that obtained a special permit, Maritimes & Northeast Pipeline, plans to take advantage of the extra capacity allowed by the higher MAOP to redirect gas supply to the New York City metropolitan area, the most capacity-strained market in the nation.

Incorporating the special permit standards into PHMSA's regulations allows qualified pipelines to operate at higher pressure. The rule eases regulatory burdens, encourages the development of new infrastructure, improves regulatory certainty, and reduces Agency workload associated with granting individual applications.

4. RATIONALE FOR REGULATORY ASSESSMENT

Executive Order 12866 directs all Federal agencies to develop both preliminary and final regulatory analyses if their regulations are likely to be "significant regulatory actions" with an annual impact on the economy of $100 million. The Order also requires a determination as to whether a proposed rule could adversely affect the economy or a section of the economy in terms of productivity and employment, the environment, public health, safety, or State, local, or tribal governments. In accordance with the regulatory philosophy and principles provided in Sections 1(a) and (b) and Section 6(a)(3)(C) of Executive Order 12866, an economic analysis of the regulatory changes must be conducted. Furthermore, the Regulatory Flexibility Act of 1980, as amended, requires Federal agencies to conduct a separate analysis of the economic impact of proposed rules on small entities. The Unfunded Mandates Act also requires an impact analysis for rules that that may result in the expenditure by State, local, and tribal governments, in the aggregate, or by the private sector, of $132 million or more ($100 million adjusted for inflation) in any one year.

In accordance with the above directives, PHMSA has performed an evaluation of the potential compliance costs of the rule and other feasible regulatory options and identified those benefits that can be expressed in monetary terms. To the extent possible, this evaluation is based on the available data and information from a range of sources including PHMSA's Incident Reporting Database and comments received from stakeholders. PHMSA estimates that the impact of implementing the rule will be greater than $100 million in any one year. PHMSA does not expect the rule to adversely affect the economy or any sector of the economy in terms of productivity and employment, the environment, public health, safety, or State, local, or tribal government. PHMSA has determined, as required by the Regulatory Flexibility Act, that the rule will not have a significant economic impact on a substantial number of small entities in the United States. In addition, PHMSA has estimated that this rule will not impose annual expenditures of $132 million or more on State, local or tribal governments or the private sector, and thus will not require an Unfunded Mandates Act analysis.

5. ALTERNATIVES CONSIDERED

In addition to taking no rulemaking action (the baseline) PHMSA considered the following two alternatives with respect to MAOP:

- Delay rulemaking
- Undertake rulemaking.

Each of these alternatives is evaluated below.

5.1 Baseline: <u>No action</u>

PHMSA could continue to address individual special permit applications on a case-by-case basis. Although this approach would give PHMSA additional oversight control, it would be less efficient for industry and for the Agency than promulgating a regulatory standard. For this reason, this is used as a baseline by which to measure costs and benefits of the other regulatory alternatives.

5.2 <u>Delay rulemaking</u>

Instead of embarking on the immediate development and implementation of a regulatory standard, PHMSA could delay rulemaking and continue to work with consensus standard-setting organizations. Current consensus standards already allow increased operating pressures, but without the additional safety requirements PHMSA has imposed in special permits. The standard-setting organization responsible for these standards is currently establishing a subcommittee to address operation of pipelines at higher pressures.

PHMSA could delay rulemaking in order to gain more experience with evaluating applications and monitoring compliance and outcomes. Furthermore, the Agency could wait until the new subcommittee of the standards organization has completed its work. A delay would then allow the Agency to have more confidence in any proposed regulatory standard it promulgates. Delaying the rulemaking, however, would necessitate continuing the less-efficient permit process. Furthermore, promulgating a rulemaking does not preclude PHMSA, at some point in the future, from reconsidering or modifying safety requirements as a result of the standard setting organization's further research. For these reasons, PHMSA rejected the option to delay the rulemaking.

5.3 Undertake rulemaking

The third alternative considered by PHMSA was to undertake a new rulemaking without undue delay. This would minimize the inefficiencies associated with the special permit process. For this reason, the rulemaking alternative was chosen by PHMSA. PHMSA will continue to entertain special permit applications for MAOP increases, to the extent permitted by the law, until such permits are determined unnecessary. The ongoing permit process will help inform any rulemaking outcome.

Furthermore, within this alternative, the Agency has explored two options: Adopt the current consensus standard as written, or adopt a rulemaking that has requirements similar to the additional safety requirements PHMSA has imposed under the special permits granted to date. Currently, the rule reflects the latter of these options. OMB Circular A-119 and the National Technology Transfer and Advancement Act of 1995 direct Federal agencies to use voluntary consensus standards in lieu of Government-unique standards in their regulatory and procurement activities, except where such standards are inconsistent with law or otherwise impractical. Therefore, this impact analysis separately estimates the impact of the additional safety requirements that differ from the consensus standard, describing why the Agency believes this is the best approach.

6. ECONOMIC ANALYSIS

With this rule, PHMSA revises the Federal pipeline safety regulations in 49 CFR Part 192 to allow use of an "alternative" MAOP when certain conditions are met. Under the rule, the alternative MAOP for each class location is as follows:

- Class 1: Greater than 72% of SMYS but less than or equal to 80% of SMYS
- Class 2: Greater than 60% of SMYS but less than or equal to 67% of SMYS
- Class 3: Greater than 50% of SMYS but less than or equal to 56% of SMYS
- Class 4: No alternative MAOP for Class 4 locations.

The conditions that must be met in order for a segment to be eligible for operation at the alternative (higher) MAOP include requirements relating to:

- Design

- Materials
- Construction
- Operation and maintenance (O&M)
- Notification.

With respect to design and materials, operators must comply with requirements for:

- The properties of the steel used for the pipe
- The manufacturing standards for the pipe
- Fracture control
- Plate quality control
- Seam quality control
- Mill hydrostatic testing
- Coating
- Fittings and flanges.

With respect to construction, operators must comply with requirements for:

- Quality assurance
- Girth welds
- Depth of cover
- Initial strength testing
- Cathodic protection
- Interference currents.

With respect to O&M, operators must comply with requirements for:

- Responding to emergencies in high consequence areas (HCAs)
- Monitoring gas quality for internal corrosion control
- Controlling interference that can impact external corrosion
- Implementing external corrosion control – cathodic protection
- Implementing external corrosion control – close interval survey
- Implementing external corrosion control – annual readings
- Patrolling the right of way
- Maintaining the depth of cover
- Reevaluating the potential impact radius as necessary
- Notifying the public proximate to the pipeline
- Performing threat identification and evaluation
- Performing indirect assessments
- Performing baseline internal inspections
- Performing additional inspections
- Performing direct assessments when internal inspection is not possible
- Evaluating anomalies conservatively and repairing defects expeditiously.

With respect to notification, operators must notify PHMSA when they choose to use an alternative MAOP.

The rule does not require operators of gas transmission pipelines to make any changes. Rather, the rule provides operators with the option of using an alternative (higher) MAOP if their pipelines meet certain specific conditions. The choice of whether to meet those conditions and use an alternative MAOP is left to the operators.

In the remainder of this section the impacted industry is identified and the affected mileage is estimated and the benefits and costs of the rule are considered. All monetary values, unless otherwise indicated, are given in 2006 constant dollars.[16]

6.1 Impacted Industry

The rule covers all existing gas transmission pipelines, of which there are approximately 320,000 miles,[17] as well as any future gas transmission pipelines.

As a result of the rule, PHMSA expects the MAOP for approximately 3,500 miles of existing pipeline to be uprated. As a practical matter, only a portion of the existing gas transmission pipeline network would be a candidate for a higher alternative MAOP, due to the requirements associated with increasing the MAOP. Many pipeline operators are expected to find the cost of using the alternative MAOP to be too high. For instance, fitting and pressure vessel replacement costs may prevent some pipeline operators from converting to a higher MAOP. Additionally, the costs associated with converting non-piggable lines are expected to be prohibitive. Also, PHMSA expects that only post-1980 pipelines will be appropriate for converting to a higher MAOP.

PHMSA expects approximately 700 miles of new gas transmission pipeline will be certificated each year to take advantage of the regulation and be operated at an alternative MAOP. This includes pipeline mileage in Class 1, 2, and 3 locations. PHMSA expects that many operators will only select an alternative MAOP for their new pipeline construction in Class 1 locations.

For this analysis, PHSMA expects that at the end of the first year after implementation of the rule, 4,200 miles of pipeline would begin to be operated at an alternative MAOP. This consists of 3,500 miles of existing pipeline and 700 miles of newly laid pipeline. Furthermore, PHMSA expects that in each subsequent year and additional 700 miles of new pipeline would begin to be operated at an alternative MAOP.

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[16] To convert nominal dollars into 2006 constant dollars, the implicit price deflator for Gross Domestic Product, transformed from 2000=100 to 2006=100, was used (for the implicit price deflators, 2000=100, see Table 1.1.9, Implicit Price Deflators for Gross Domestic Product, Bureau of Economic Analysis, National Income Accounts). The 2006 deflator (2000=100) was calculated by averaging the quarterly implicit price deflators for the first and second quarters of 2006.

[17] See PHMSA, Distribution & Transmission Annual Mileage Totals (1984-2005), http://ops.dot.gov/stats/stats.htm.

6.2 Benefits

The main expected benefits of the rule are the following:

- A reduction of the consequences (e.g., deaths, injuries, property damage, and lost gas) resulting from pipeline incidents.
- Fuel cost savings.
- A reduction in pipeline capital expenditures.
- An increase in pipeline capacity.
- An increase in line pack.
- A reduction in adverse environmental impacts.

These benefits are discussed below. Following the discussion of each individual benefit, the total benefits and their present value are estimated. The benefits discussion concludes with a review of benefits uncertainties.

6.2.1 Reduced Incident Consequences from Pipeline Incidents

The operation of natural gas transmission pipelines at higher MAOP is not expected to increase the number or severity of pipeline incidents.[18] The rule's requirements, such as monthly right-of-way patrolling, additional internal inspections, and anomaly repair, are expected to prevent incidents that would have occurred in the absence of the rule, and to help mitigate the consequences of the incidents that do occur.

A quantitative estimate of the benefits associated with reduced incident consequences is not developed for this analysis. While PHMSA expects the rule to reduce the incidents and incident consequences on the pipeline mileage affected by the rule, quantification of the benefits resulting from those reductions would be difficult. For instance, differentiating the benefits attributable to increased right-of-way patrolling from those attributable to other regulatory safety requirements relating to the prevention or mitigation of excavation or natural forces damage may be impracticable for analytical purposes. As another example, differentiating the benefits attributable to additional internal pipeline inspections from those attributable to other regulatory safety requirements relating to corrosion damage prevention and control may present similar challenges.

Additionally, PHMSA expects that some pipeline operators have already adopted the practices required by the rule. As a result, the estimated benefits associated with the safety improvements attributable to the rule are reduced.

[18] See, for instance, Joy O. Kadner, PHMSA, "Reconsideration of Maximum Allowable Operating Pressures for Natural Gas Pipelines," PHMSA-2006-23447-46; Alan Eastman, Mears Group, Inc., "Impact of 80% SMYS Operation on Time Dependent Threats," PHMSA-2006-23447-28.

6.2.2 Fuel Cost Savings

Natural gas engines or turbines are frequently used to drive the compressors that move the product through gas transmission pipelines. Industry expects the rule will reduce fuel costs for pipeline owners operating existing pipelines at an alternative MAOP.

In a submission to PHMSA relating to its petition to increase the MAOP on 874.7 miles of pipeline in the U.S. from 72% of SMYS to 80% of SYMS, Alliance Pipeline estimated that it could save $11.9 million on its fuel costs in 2007 with the higher MAOP. In calculating this estimate, gas was assumed to cost $5.72 per million BTUs (British thermal units).[19]

For this analysis, PHMSA assumes that the annual fuel cost savings realized by operators of pipelines choosing to go with an alternative MAOP would be $14,000 per mile ($11.9 million / 874.7 miles). This estimate is based on the fuel cost savings information provided by Alliance Pipeline. For existing pipelines, this would be the major benefit of changing the formula for calculating MAOP. New pipelines built with thinner-walled pipe would not, however, see this same benefit.

Assuming that 3,500 miles of existing pipeline are initially affected in the first year, the total cost savings in that year would be $49 million ($14,000 * 3,500 miles). It should be noted that all fuel savings are annually recurring. That is, they will continue to be realized each and every year after an existing pipeline operates at an alternative MAOP.[20]

6.2.3 Reduced Capital Expenditures

In constructing new pipelines, companies have another option as a result of this rulemaking: instead of building the pipeline to the standard currently required and increasing its pressure, they can reduce the wall thickness of the new pipeline (thus resulting in savings on steel cost)[21] to achieve the "same" operating pressure under the new formula for calculating MAOP. This is a straightforward result from the formula for calculating MAOP below; increasing the design factor allows either pressure to go up or wall thickness to go down. For this analysis, PHMSA assumes that new pipelines would choose to take advantage of reduced capital expenditures.

To determine the wall thickness of pipe (t) needed for a specific operating pressure (P), an operator would use the design formula specified in § 192.105 and solve for t as follows:

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[19] Submission by Alliance Pipeline, L.P., to PHMSA, Feb. 20, 2006, PHMSA-2005-23387-8.

[20] This analysis does not attempt to forecast the increased benefits as fuel costs rise.

[21] See, for example, the response by BP Canada Energy Marketing Corp. to dockets PHMSA-2005-23387, PHMSA-2005-23447, and PHMSA-2005-23448 or Howard J. Murphy, Jr., Energy Experts International, "Reconsideration of Maximum Allowable Operating Pressure: Costs and Benefits – A Macroeconomic View," PHMSA-2006-23447-35.

$$t = (P \times D) / (2 \times S \times F).$$[22]

The increase in the design factor F in this rulemaking results in a decreased value for t. The use of thinner walled pipe results in a savings in the amount of steel needed.

Information on the total capital expenditure savings attributable to the use of an alternative MAOP by pipeline operators is not readily available. Neither is information on the capital expenditure savings attributable to the expected reduction in the required investment in compressors for existing pipelines. PHMSA has developed an estimate for the capital expenditure savings attributable to the expected reduction in the required investment in pipe, which is based on information obtained by PHMSA from materials submitted in support of special permits for five pipeline projects. That information is presented in Table 1. PHMSA's estimate of the expected reduction in the required investment in pipe is $78,260 per mile ([**$1,644,426,015** - **$1,482,036,466**] / 2,075 miles). The estimate assumes that the cost of steel for pipe is $1,300 per ton.

TABLE 1. STEEL PIPE COST COMPARISON: PIPELINES OPERATING AT 72% OF SMYS VERSUS PIPELINES OPERATING AT 80% OF SMYS PIPELINE PROJECT CHARACTERISTICS

	Project	**Status**	**Pipe size (Inches)**	**MAOP (psig)**	**Grade of steel (psi)**	**Project length (Miles)**	**Project length (Feet)**
1	Gulf South	Special permit granted	42	1333	70000	212	1,119,360
2	CenterPoint	Special permit granted	42	1168	70000	170	897,600
3	REX	Special permit granted	42	1481	80000	1323	6,985,440
4	KMLP	Special permit granted	42	1440	70000	137	723,360
5	Ozark	Special Permit Pending	24	1200	70000	8	42,240
6	Ozark		36	1200	70000	225	1,188,000
	TOTAL					**2,075**	10,956,000

[22] D and S are defined in §192.105 as the nominal diameter of the pipe and its yield strength, respectively.

ESTIMATED COST OF STEEL WITH PIPELINE OPERATING AT 72% OF SMYS

	Project	Pipe size (Inches)	Pipe wall thickness (Inches)	Weight of steel per foot (Pounds)	Total weight of steel (Tons)	Estimated total cost of steel*
1	Gulf South	42	0.56	246.0732	137,722	$179,038,953
2	CenterPoint	42	0.49	215.9717	96,928.11	$126,006,547
3	REX	42	0.54	239.332	835,919.65	$1,086,695,543
4	KMLP	42	0.60	265.5396	96,040.36	$124,852,471
5	Ozark	24	0.29	72.4302	1,529.73	$1,988,643
6	Ozark	36	0.43	162.968	96,802.97	$125,843,858
	TOTAL					**$1,644,426,015**

ESTIMATED COST OF STEEL WITH PIPELINE OPERATING AT 80% OF SMYS

	Project	Pipe Size (Inches)	Pipe wall thickness (Inches)	Weight of steel per foot (Pounds)	Total weight of steel (Tons)	Estimated total cost of steel*
1	Gulf South	42	0.500	221.8175	124,146.82	$161,390,863
2	CenterPoint	42	0.438	194.6024	87,337.57	$113,538,840
3	REX	42	0.486	215.6793	753,307.56	$979,299,829
4	KMLP	42	0.540	239.332	86,561.60	$112,530,075
5	Ozark	24	0.258	65.48091	1,382.96	$1,797,843
6	Ozark	36	0.386	146.9555	87,291.55	$113,479,016
	TOTAL					**$1,482,036,466**

*Cost of steel estimated at $1,300 per ton.
Source: Materials submitted to PHMSA in support of special permits.

Assuming that 700 miles of new pipeline are initially affected by the rule in the first year and that 700 miles of new pipeline are added each year thereafter, the expected annual capital expenditure savings attributable to the reduction in pipe investment would be approximately $54.6 million ($78,000 per mile * 700 miles). This estimate does not include any capital expenditure savings attributable to compressor investment for existing pipelines, a savings that could be sizable.[23]

6.2.4 Increased Pipeline Capacity

In the case of new pipelines, the ability to use an alternative MAOP will make it possible to transport more of the product. Quantifying the value of this increased capacity is

[23] For estimates of the potential savings on compressor investment on the Alaska Natural Gas Transportation System, see Howard J. Murphy, Jr., Energy Experts International, "Reconsideration of Maximum Allowable Operating Pressure: Costs and Benefits – A Macroeconomic View," PHMSA-2006-23447-35.

difficult, and no estimate has been developed for this analysis. Nonetheless, PHMSA expects the value of increased capacity due to use of alternative MAOP by gas pipelines to be significant. Estimates made with respect to the proposed trans-Alaskan gas pipeline include an estimated increase of 14.2 million standard cubic feet of gas per day.[24] In areas where production is already well established, there is an even greater potential for increased pipeline capacity. For example, one recipient of a special permit estimated a daily increase of at least 62 million standard cubic feet of gas.[25] In addition to simply being better able to meet demand, increased capacity will eventually mean cost savings with the elimination of the need for some future pipelines (i.e., the capacity added by using an alternative MAOP may eliminate the need to construct a new pipeline with that capacity at some later date).

6.2.5 Increased Line Pack

"Line pack" is essentially the quantity of natural gas filling a pipeline or pipeline segment and the amount of line pack varies by pressure in the pipeline. On pipelines using an alternative MAOP, the line pack would be greater than it would be if an alternative MAOP were not used. Line pack may be either owned by the pipeline operator or provided by its customers.

Increased line pack has several advantages. First, it reduces the amount of external storage that is needed for natural gas. The reduction in the amount of external storage needed may result in capital or O&M cost savings for pipeline operators or their customers. Currently in the U.S., an estimated 95 to 98 percent of external natural gas storage is underground in depleted oil or gas reservoirs that have been retrofitted to handle gas injection and withdrawal.[26] Added storage via increased line pack could be particularly important in areas where underground storage is limited, such as in the Southwest.[27]

Second, increased line pack allows more product to be delivered to customers when segments of a pipeline must be (1) taken out of service for routine maintenance or (2) shut down due to pipeline accidents or problems with pipeline valves, compressors, or other equipment.

Third, increased line pack allows pipelines greater latitude in covering peaks in natural gas demand. This would be of value serving certain natural gas consumers, such as electric utilities, "...with load profiles that are not uniform."[28]

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[24] Howard J. Murphy, Jr., Energy Experts International, "Reconsideration of Maximum Allowable Operating Pressure: Costs and Benefits – A Macroeconomic View," PHMSA-2006-23447-35.
[25] Special Permit Analysis and Findings, Gulf South Pipeline Company, PHMSA-2006-26533-4.
[26] Jeffrey H. Foutch, "Times Are Changing for Gas Storage," http://www.falcongasstorage.com/_filelib/FileCabinet/Articles/Times%20are%20Changing.pdf?FileName=Times%20are%20Changing.pdf.
[27] Submission by Kern River Gas Transmission Company, Docket No. PHMSA-2005-23447-23.
[28] Ibid..

The value of these and any other benefits attributable to increased line pack cannot be readily quantified, but may be substantial. PHMSA believes the reduced amount of exterior storage capacity needed resulting from increased line pack may result in capital or operation and maintenance savings for the pipelines or their customers. Increased line pack increases the ability to continue gas delivery during short outages such as maintenance and to increase the amount of gas quickly during peak periods.

6.2.6 Reduced Adverse Environmental Impacts

Allowing pipeline operators to use an alternative MAOP would have environmental benefits. Because of the potential for increased capacity by pipelines using an alternative MAOP, fewer pipelines might be needed. This means that, all other things equal, less local ecology would be disturbed by the construction of new pipelines and fewer environmentally sensitive areas would be disturbed by operation and maintenance activities, such as pipeline repairs. In addition, the new requirements are expected to reduce the likelihood of leaks, and thereby reduce the potential harm that natural gas escaping from those leaks could have on the atmosphere. The value of the environmental benefits resulting from the use of an alternative MAOP cannot be readily quantified. It may be substantial, however.

6.2.7 Other Expected Benefits

PHMSA notes that a number of additional benefits would result from the rule. Those benefits include the reduction of certain costs, other than steel costs, associated with the construction of new pipelines (e.g., pipe transport, compressor, and welding costs). Although not quantified in this report, these additional benefits are expected to be substantial.

6.2.8 Total Benefits

Table 2 presents a summary of the estimated benefits of the rule. As a consequence of the rule, PHMSA estimates that pipeline operators will realize annually recurring benefits of $49 million in fuel cost savings that begin in the initial year after the rule goes into effect. Additionally, PHMSA estimates that each year, pipeline operators will realize one-time, non-recurring benefits of $54.6 million (since 700 miles of new pipeline operating at an alternative MAOP are added each year, the one-time benefits resulting from this added mileage will be the same each year). In total, operators will realize $103.6 million ($49.0 million + $54.6 million) in benefits per year. These estimates only include the benefits attributable to (1) fuel savings and (2) reduced capital expenditures related to pipe on new pipelines. Estimates do not include any benefits attributable to (1) reduced incident consequences, (2) reduced capital expenditures related to compressors on new pipelines, (3) increased pipeline capacity, (4) increased line pack, (5) less environmental disturbance, or (6) other improvements, since those benefits were not quantified in analysis. PHMSA believes these additional benefits could add millions, and potentially hundreds of millions, to the total benefits.

TABLE 2. SUMMARY AND TOTAL FOR THE ESTIMATED BENEFITS OF THE RULE

Benefit	Estimate for Year 1 ($ Million)	Estimate of benefits occurring in each subsequent year ($ Million)
Reduced incident consequences	Not quantified	Not quantified
Fuel cost savings	$49.0	$49.0
Reduced capital expenditures	$54.6	$54.6
Increased pipeline capacity	Not quantified	Not quantified
Increased line pack	Not quantified	Not quantified
Reduced adverse environmental impacts	Not quantified	Not quantified
Other expected benefits	Not quantified	Not quantified
TOTAL	**$103.6**	**$103.6**

The present value of the estimated benefits and the annualized value of benefits over 20 years using 3 percent and 7 percent discount rates are presented in Table 3. When considering the present value estimates, it should be remembered that they do not include the non-quantified benefits, which are likely to be significant.

TABLE 3. PRESENT AND ANNUALIZED VALUE OF THE ESTIMATED BENEFITS CALCULATED OVER 20 YEARS

Discount rate	Present value of benefits ($ Million)	Annualized value of benefits ($ Million)
3%	1,541	101
7%	1,098	97

6.2.9 Benefit Uncertainties

The benefit estimates developed for this rule are built on several key assumptions:

- Pipeline operators using an alternative MAOP will experience annual fuel cost savings of $14,000 per mile. This estimate depends on the price of gas.
- 4,200 miles of pipeline (3,500 miles of existing pipeline plus 700 miles of new pipeline) will adopt an alternative MAOP in the first year after implementation of the rule and an additional 700 miles of pipeline will begin to use an alternative MAOP in each succeeding year.
- Pipeline operators with new pipelines using an alternative MAOP will experience a capital expenditure cost savings attributable to pipe of $78,000 per mile.

These assumptions introduce uncertainties into the benefits calculations. The impacts of these uncertainties on the benefits estimates are discussed below.

Impact of Fuel Cost Savings Per Mile

The fuel saving per mile when an alternative MAOP is used may be lower than the $14,000 used in this analysis, or it may be higher. Table 4 presents the benefits that would result if the fuel savings per mile were decreased or increased by 50 percent (i.e., decreased to $7,000 per mile or increased to $21,000 per mile).

TABLE 4. BENEFITS WITH FUEL COST SAVINGS PER MILE CHANGED BY PLUS OR MINUS 50%

Benefits	Fuel cost savings per mile decreased by 50% ($ Million)	Fuel cost savings per mile increased by 50% ($ Million)
	Estimate	**Estimate**
Recurring	$24.5	$73.5
One-time	$54.6	$54.6
Discount rate and number of years	**Present value**	**Present value**
3% and 20 years	$1,177	$1,906
7% and 20 years	$838	$1,357

When the fuel cost savings are increased by 50 percent, the present value of the benefits increase to 124 percent of the present value of the benefits under the base case. When the fuel cost savings are decreased by 50 percent, the present value of the benefits decreases to 76 percent of the present value of the base case. Thus, a 50 percent change in the fuel cost savings generates a 24 percent change in the present value of the benefits.

Impact of Pipeline Mileages with an Alternative MAOP

The actual pipeline mileages with which an alternative MAOP is used may be lower than those used in this analysis, or they may be higher. Table 5 presents the benefits that would result if the pipeline mileages were decreased or increased by 50 percent.

TABLE 5. BENEFITS WITH MILEAGE CHANGED BY PLUS OR MINUS 50%

Benefits	**Mileage decreased by 50% ($ Million)**	**Mileage increased by 50% ($ Million)**
	Estimate	**Estimate**
Recurring	$24.5	$73.5
One-time	$27.3	$81.9
Discount rate and number of years	**Present value**	**Present value**
3% and 20 years	$771	$2,312
7% and 20 years	$549	$1,664

When the mileage is reduced to 2,100 miles in the first year, with 350 miles in each subsequent year (i.e., by 50 percent), the present values are half of what was estimated using the 4,200 and 700 mileage values. When the mileage is increased to 6,300 miles in the first year, with 1,150 miles in each subsequent year (i.e., by 50 percent), the present values also increase by 50 percent.

Following implementation of the rule, it is possible that the addition of new pipeline based on an alternative MAOP might only occur for a few years, rather than for 20 years. PHMSA estimates that approximately 3,500 miles of new gas transmission pipeline certificated in the next 5 years would be operated at an alternative MAOP. Table 6 presents the benefits that would result if only those 3,500 miles of new pipeline were to use an alternative MAOP.

TABLE 6. THE ESTIMATED BENEFITS IF ADDITION OF 700 MILES PER YEAR ONLY OCCURS DURING FIRST 5 YEARS

Benefits	**Estimate ($ Million)**
Recurring	$49.0
One-time	$54.6
Discount rate and number of years	**Present value ($ Million)**
3% and 20 years	$979
7% and 20 years	$743

This change reduces the present value of the benefits to 64 or 68 percent of what it is under the base case. While this change would result in a reduction in the present value of the benefits of hundreds of millions of dollars, the resulting present values still approach $1 billion.

Impact of Capital Expenditure Savings on Pipe for New Pipelines

The capital expenditure savings on pipe for new pipelines when an alternative MAOP is used may be lower than the $78,000 per mile used in this analysis, or it may be higher (especially since PHMSA did not include possible savings due to other capital expenditures besides steel cost). Table 7 presents the benefits that would result if the fuel savings per mile were decreased or increased by 50 percent (i.e., decreased to $39,000 per mile or increased to $117,000 per mile).

TABLE 7. BENEFITS WITH CAPTIAL EXPENDITURE SAVINGS FOR PIPE ON NEW PIPELINES CHANGED BY PLUS OR MINUS 50%

Benefits	Mileage decreased by 50% ($ Million)	Mileage increased by 50% ($ Million)
	Estimate	**Estimate**
Recurring	$49.0	$49.0
One-time	$27.3	$81.9
Discount rate and number of years	**Present value**	**Present value**
3% and 20 years	$1,135	$1,947
7% and 20 years	$808	$1,387

When the capital expenditure savings are increased by 50 percent, the present value of the benefits increases to 126 percent of the present value of the benefits under the base case. When the capital expenditure savings are decreased by 50 percent, the present value of the benefits decreases to 74 percent of the present value of the base case. Thus, a 50 percent change in the capital expenditure savings generates a 26 percent change in the present value of the benefits.

6.3 Costs

The rule does not require operators of natural gas transmission systems to use an alternative MAOP on their pipeline systems. Rather, it provides operators with pipeline in Class 1, 2, or 3 locations with the option to use an alternative MAOP under certain circumstances. The rule will cost operators only if they choose to use an alternative MAOP on their pipelines; however, the benefits summarized above will only be realized under the assumption that these voluntary costs are also incurred.

For the most part, the rule merely codifies existing best practices with respect to pipeline design, materials, construction, and O&M. In many cases, pipeline operators have already adopted these best practices as part of their standard operating procedures. Operators are already performing some of the actions required by the rule, and so the rule imposes few new costs.

PHMSA expects costs attributable to the rule are most likely to be incurred by operators for:

- Performing baseline internal inspections
- Performing additional internal inspections
- Performing anomaly repairs
- Installing remotely controlled valves on either side of high consequence areas (HCAs)
- Preparing threat identification and evaluation
- Patrolling pipeline rights-of-way
- Notifying PHMSA.

These costs are discussed below. Following the discussion of each individual cost, total costs and the present value of those total costs are calculated. The uncertainties relating to the cost estimates are then discussed.

6.3.1 Performing Baseline Internal Inspections

The rule requires the operators of new pipelines electing to use an alternative MAOP to perform a baseline internal assessment. The assessment must use a high-resolution magnetic flux tool and be conducted within 3 years of placing the pipeline in service. In addition, the assessment requires the use of a geometry tool after the initial hydrostatic test and backfill no later than 6 months after placing the pipeline in service. The operators of existing lines electing to use an alternative MAOP must complete a baseline assessment using the same tools within 2 years of raising the MAOP.

Even without the rule, PHMSA expects operators to perform the required tests on new pipelines. Thus, new pipelines would incur no additional costs attributable to the baseline internal inspection requirement of the rule. Existing pipelines that are uprated will need the two tests, and in the absence of the rule, those tests would not ordinarily be performed.

Both of the tests on the existing pipeline mileage will be accomplished through the use of "smart pigs." The Interstate Natural Gas Association of America (INGAA) has previously estimated that the cost of smart-pigging transmission pipelines is $3,669 per mile (in 2001 dollars).[29] This is $4,160 per mile when converted to 2006 dollars.

To simplify computation, both tests are assumed to be completed in the first year after the rule is implemented.[30] The total cost of the tests would be approximately $29.1 million (3,500 miles of pipeline * $4,160 per mile * 2). This cost would be incurred only once.

[29] Final Regulatory Evaluation, Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines), p. 43, RSPA-2000-7666-356.

[30] This will increase the present value of the costs slightly, since the present value of $1 in the first year is greater than the present value of $1 in the second or third years.

6.3.2 Performing Additional Internal Inspections

The rule requires periodic internal inspections using a high resolution magnetic flux tool on a frequency determined as if the segments were covered by 49 CFR 192 subpart O ("Gas Transmission Pipeline Integrity Management"). After baseline internal inspection has been completed, operators will need to use a smart pig (or equivalent) on their lines at least once every 10 years.

PHMSA estimates that the cost of smart-pigging a pipeline is $4,160 per mile (see Section 6.3.1). Furthermore, PHMSA expects that this requirement would impact 4,200 miles of pipeline in the 11th year after implementation of the rule and 700 miles of pipeline each year thereafter.[31] In the 11th year, pipeline operators would incur $17.5 million (4,200 miles * $4,160 per mile) in costs attributable to this requirement, while in years 12 through 20 they would incur $2.9 million (700 miles * $4,160 per mile) per year attributable to the requirement.

6.3.3 Performing Anomaly Repairs

The rule requires that certain anomalies be repaired immediately, when identified, and certain others be repaired within 1-year of their discovery.

Given the requirements of 49 CFR 192.309, PHMSA does not expect that the repair requirements of the rule will cause any newly laid pipelines to incur additional costs. Only existing pipelines are expected to incur additional costs attributable to the repair requirement. Furthermore, PHMSA expects the needed repairs to be identified primarily through internal inspections.

PHSMA does not have estimates of the immediate and 1-year repair rates for transmission pipelines operating at a higher stress level. PHMSA does have immediate and 1-year repair rates for transmission pipelines in HCAs, however. Those rates, derived from gas integrity management program performance metric submissions as of December 2006, are 0.03 immediate repairs per mile inspected and 0.08 one-year repairs per mile inspected. Overall, the sum of immediate and 1-year repair rates is 0.11 repairs per mile (0.03 immediate repairs per mile + 0.08 1-year repairs per mile).

PHMSA notes that these rates are for older pipelines, most not designed and constructed, or operated and maintained to the rigorous standards required under the rule. Furthermore, since inspections are prioritized based on risk, these estimates should be for the riskier pipeline segments within HCAs. Consequently, PHMSA expects that the rates for pipelines operating at higher stress levels would be significantly lower than 0.11 repairs per mile. For this analysis, PHMSA assumes that the immediate and 1-year repairs will be 10 percent of the 0.11 repairs per mile, or 0.01 repairs per mile for gas transmission pipelines using an alternative MAOP. For ease of computation, it is assumed that all anomalies are discovered and repaired within the same year.

[31] The cycle would begin over in the 21st year, which is beyond the scope of this analysis.

The U.S. Environmental Protection Agency (EPA) has estimated that the total cost of repairing a 6-inch, non-leaking defect by replacing the pipe in a 24-inch steel pipeline operated at 350 pounds per square inch gage (psig) with 10 miles between shutoff valves would be $22,746 (based on the publication date, this estimate is presumed to be expressed in 2003 dollars). This estimate includes the costs associated with (1) lost methane, (2) purge gas, (3) labor, (4) equipment and material, and (5) indirect costs.[32]

Duke Energy Gas Transmission and INGAA have estimated that the total cost of repairing a 6-inch, non-leaking defect by replacing 6 feet of pipe in a 24-inch steel pipeline operated at 350 psig with 10 miles between block valves would be $15,300 (based on the publication date, this estimate is presumed to be expressed in 2004 dollars). This estimate includes the costs associated with (1) purge gas, (2) labor, (3) equipment and material, and (4) other. It does not include the value of lost methane, which was estimated to be $11,900 (presumably in 2004 dollars).[33]

For this analysis, the cost of repairing a steel pipeline is assumed to be $29,000. This is based on the estimates for replacing the steel piping by Duke and INGAA, including the value of lost gas. While using a composite wrap would cost significantly less (i.e., roughly 20 percent of the cost of replacing the steel pipe when the cost of lost gas is included), its appropriateness for use on pipelines operating at an alternative MAOP is unknown.

In total, the cost per mile of repairing defects is estimated to be $290 per mile (0.01 per mile x $29,000). Repairs will be undertaken after internal inspection. A total of 3,500 miles of existing pipeline will be internally inspected in the first year after implementation of the rule (see Section 6.3.1). After this inspection, pipeline operators will incur repair costs of approximately $1.0 million (3,500 miles * $290 per mile). In the eleventh year after implementation a total of 4,200 miles of pipeline will be internally inspected (see Section 6.3.2). After this inspection, pipeline operators will incur repair costs of approximately $1.2 million (4,200 miles * $290 per mile). In each subsequent year, a total of 700 miles of pipeline will be internally inspected (see Section 6.3.2). After each of these inspections, pipeline operators will incur repair costs of $203,000 (700 miles x $290 per mile).

6.3.4 Installing Remotely Controlled Valves at HCAs

The rule requires that mainline valves on either side of an HCA be remotely controlled via a SCADA (Supervisory Control and Data Acquisition) system or other, alternative method, if personnel response time to the valves exceeds one hour. The valves covered by this requirement are not necessarily at the boundary of each HCA, but rather are the

[32] "Lessons Learned From Natural Gas STAR Partners: Composite Wrap for Non-Leaking Pipeline Defects," U.S. EPA, July 2003, http://www.epa.gov/gasstar/pdf/lessons/ll_compwrap.pdf. .

[33] "Composite Wrap for Non-Leaking Pipeline Defects," Duke Energy Gas Transmission, INGAA, and EPA's Natural Gas STAR Program, September 22, 2004, http://www.epa.gov/gasstar/workshops/houston-sept22/CompositeWrapforPipelineDefects.ppt.

closest valves to the HCA on the pipeline. PHMSA notes that many operators currently choose to automate these valves.

PHSMA expects that the rule will result in the installation of 12 additional remotely controlled mainline valves per thousand miles of pipeline. PHMSA estimates that the cost for these valves for a 42-inch gas transmission pipeline would be approximately $70,000.

For this analysis, PHMSA assumes that the cost of remotely controlled valves would be $70,000. This probably overstates the cost, since valves for pipelines with smaller diameters would cost less than those used with a 42-inch pipeline.

The cost of the requirement to install remotely controlled valves at HCAs when the response time for personnel exceeds one hour will be $840,000 per thousand miles of pipeline (12 remotely controlled valves * $70,000 per valve). Assuming that an alternative MAOP would be adopted for 4,200 miles of pipeline in the first year after the rule is implemented, the total cost of the requirement in the first year would be $3.5 million (4,200 miles * $840,000 per thousand miles). The total cost in each subsequent year would be $588,000 (700 miles * $840,000 per thousand miles). These would be one-time costs.

For new pipelines, these estimates probably overstate actual costs, since pipeline operators would likely be purchasing remotely controlled valves in place of valves that are not remotely controlled. For all pipelines, the estimated cost, $70,000 per valve, probably overstates the average cost of the remotely controlled valves that operators would purchase. Consequently, the estimates developed here probably overstate the actual costs of the requirement.

6.3.5 Preparing Threat Identification and Evaluations

The rule requires operators electing to use an alternative MAOP to develop a threat matrix identifying and comparing the increased changes in risk of operating their pipelines at the increased stress level. Additionally, operators must describe the procedures they will take to mitigate the risk.

Kinder Morgan has been involved in the preparation of threat assessments for three pipelines seeking approval to use the alternative method to establish MAOP: (1) Rockies Express, (2) Kinder Morgan Louisiana, and (3) Midcontinent Express. Those threat assessments are reported to have cost $16,000, $7,000, and $8,000, respectively. The costs are made up entirely of labor charges. The analytical tool used for the threat assessments had been previously acquired to perform the threat assessments needed for gas transmission pipeline Integrity Management. The data used for the threat assessments had been acquired to support Federal Energy Regulatory Commission permitting requirements for the pipelines.[34] Based on this information, PHMSA estimates that each

[34] Communication between M. Dwayne Burton, KinderMorgan, and Paul Zebe, Volpe Center, August 3, 2007.

threat identification and evaluation required for the rule will cost $10,000 ([$16,000 + $7,000 + $8,000]/3).

The number of pipelines needing to prepare threat identification and evaluations is unknown and must be estimated. In 2006, PHMSA received 1393 reports covering 320,532 miles of gas transmission and gathering system pipeline. On average, each report covered approximately 230 miles of pipeline (320,532 miles / 1393 reports). Assuming that each report covered, on average, one pipeline, PHMSA expects the 4,200 miles of pipeline adopting an alternative MAOP in the first year if the rule is implemented to consist of 18 pipelines (4,200 miles / 230 miles per pipeline). The 700 miles of additional pipeline that is expected to adopt an alternative MAOP in subsequent years is estimated to consist of 3 pipelines (700 miles / 230 miles per pipeline). Based on the foregoing, the costs resulting from preparing threat identification and evaluations are expected to be $180,000 in the first year if the rule is implemented ($10,000 * 18) and $30,000 in each subsequent year ($10,000 * 3). For this analysis, this is treated as a one-time cost. In reality, updates would be required if and when changes in risk occurred. These updates would not be expected to cost as much as the original threat identification and evaluations.

6.3.6 Patrolling Rights-of-Way

The rule requires monthly patrolling of the rights-of-way for pipelines using an alternative MAOP. Patrols must be performed once a month but not to exceed 45 days apart. The purpose of the patrols is to inspect for excavation activities, ground movement, wash outs, leakage, or other activities or conditions affecting pipeline integrity.

Currently, under Section 192.705, gas transmission lines must be patrolled periodically. At highway and railroad crossings, pipelines in Class 1, 2, and 3 locations must be patrolled at least four times per year. At all other places, pipelines in Class 1 and 2 locations must be patrolled at least once per year, while pipelines in Class 3 locations must be patrolled at least two times per year.

PHMSA estimates that it costs $25,000 to patrol 250 miles of pipeline (i.e., $100 per pipeline mile). This cost estimate includes the fully loaded cost of one person plus the cost of ground transportation along the pipeline.

For this analysis, PHMSA assumes that the new patrolling requirement would add 11 additional patrols per pipeline mile per year. PHIMSA assumes that currently two patrols occur on average during a year and that under the rule a total of 13 patrols would be needed (52 weeks / 4). The cost of 11 added patrols would be $1,100 per pipeline mile per year (11 patrols per year * $100 per pipeline mile). When the rule is implemented, in the first year 4,200 miles of pipeline would need to be patrolled. The total cost of patrolling 4,200 miles would be $4.6 million ($1,100 per mile, per year * 4,200 miles). In subsequent years, an additional $770,000 would be added annually ($1,100 per mile per year * 700 miles) to the patrolling cost of the previous year. Table 8 presents the estimated patrolling costs for the first 20 years after implementation of the rule. The total cost over the 20 years is estimated at $238.7 million.

TABLE 8. ESTIMATED PATROLLING COSTS

Year	Patrolled mileage	Patrolling cost ($ Thousand)
1	4,200	4,620
2	4,900	5,390
3	5,600	6,160
4	6,300	6,930
5	7,000	7,700
6	7,700	8,470
7	8,400	9,240
8	9,100	10,010
9	9,800	10,780
10	10,500	11,550
11	11,200	12,320
12	11,900	13,090
13	12,600	13,860
14	13,300	14,630
15	14,000	15,400
16	14,700	16,170
17	15,400	16,940
18	16,100	17,710
19	16,800	18,480
20	17,500	19,250
Total		**238,700**

6.3.7 Notifying PHMSA of the Decision to Use an Alternative MAOP

The rule contains information collection requirements. The rule requires pipeline operators to notify PHMSA if they elect to operate at an alternative MAOP. The rule requires an operator to notify PHMSA, and state pipeline safety regulators exercising jurisdiction, when it elects to establish an alternative MAOP. Operators are required to furnish evaluation reports, prepare notification letters, disseminate public notices, and keep records. The notification and threat identification and evaluation requirements are described in Section 192.112, Section 192,328, and Section 192.620. These requirements will allow the Agency to validate the operators' conclusions.

The requirements are as follows:

- *Section 192.112,* requires operators to notify PHMSA, and a State pipeline safety authority, when the pipeline is located in a State where PHMSA has an interstate agent agreement, results of pipeline safety tests, research, and analyses anywhere between 60 and 180 days before operating at the alternative maximum allowable operating pressure.

- *Section 192.328(d) and Section 192.620(b),* requires operators to notify PHMSA of the results of their MAOP related evaluations and analysis results. Under this section operators must furnish reports to each PHMSA pipeline safety regional office where the pipe is in service at least 60 days prior to operating at the alternative MAOP. An operator must also notify a State pipeline safety authority when the pipeline is located in a State where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that State.
- *Sections 192.620(d)(1)* requires an operator to prepare a threat identification and evaluation consistent with the identification and evaluations done under integrity management to address the risks of operating at an increased stress level.
- *Section 192.620(d)(2),* requires operators, not in an High Consequence Area (HCA) to inform any stakeholders living along the right of way of any increase in MAOP in their pipeline systems. Where the alternative MAOP pipeline is in an HCA already identified per Subpart O, then no additional notification is necessary besides what is already required.
- *Sections 192.620(c)(1), (2), and (3),* requires an operator to notify PHMSA, and applicable state pipeline safety regulators, when it elects to establish an alternative MAOP. In addition it requires an operator to further notify PHMSA when it has completed the actions necessary to support operation at an alternative MAOP, by submitting a certification by a senior executive that the pipeline meets the requirements for operation at alternative MAOP. The certification is required by paragraph (c)(2). A senior executive must certify that the pipeline meets the additional design and construction regulations of this rule. A senior executive must also certify that the operator has changed its operation and maintenance procedures to include the more rigorous additional operation and maintenance requirements. In addition, a senior executive must certify that the operator has reviewed its damage prevention program in light of best practices, such as Common Ground Alliance best practices or some equivalent best practices, and made any needed changes to it to ensure that the program meets or exceeds those standards or practices. The certification must be submitted at least 30 days prior to operation at an alternative MAOP.
- *Section 192.620(d)(8),* requires operators to notify the PHMSA Regional Office where pipeline is located (and states where appropriate) if inadequate CP readings are not addressed within six months, providing the reason for the delay and a justification that the delay is not inimical to pipeline safety.

6.3.8 Total Costs

Tables 9 and 10 present summaries of the estimated costs of the rule over 20 years, along with the calculated totals for those costs by year. In total, the costs of the rule are expected to be $38.5million in the 1st year, go from approximately $6.0 million in the 2nd year to $12.2 million in the 10th year, be $31.6 million in the 11th year, and then go from $16.8 million in the 12th year to $23.0 million in the 20th year.

TABLE 9. SUMMARY AND TOTALS FOR THE ESTIMATED COSTS OF THE RULE

Cost item	Cost By year after implementation ($ Thousand)			
	Year 1	Years 2–10	Year 11	Years 12–20
Baseline internal inspections	$29,119	None	None	None
Additional internal inspections	None	None	$17,471	$2,912 each year
Anomaly repairs	$1,015	None	$1,218	$203 each year
Remotely controlled valves	$3,528	$588 each year	$588	$588 each year
Threat identification and evaluations	$180	$30 each year	$30	$30 each year
Patrolling	$4,620	$5,390 to $11,550 (see Table 8)	$12,320	$13,090 to $19,250 (see Table 8)
Notifying PHMSA	Nominal	Nominal	Nominal	Nominal
TOTAL	**$38,462**	**$618 each year plus patrolling costs in Table 8**	**$31,627**	**$3,733 each year plus patrolling costs in Table 8**

TABLE 10. ESTIMATED TOTAL COSTS BY YEAR

Year	Total cost ($ Million)	Present value of costs discounted at 3% ($ Million)	Present value of costs discounted at 7% ($ Million)
1	38.5	37.3	35.9
2	6.0	5.7	5.2
3	6.8	6.2	5.5
4	7.6	6.7	5.8
5	8,.3	7.2	5.9
6	9.1	7.6	6.1
7	9.9	8.0	6.1
8	10.6	8.4	6.2
9	11.4	8.7	6.2
10	12.2	9.1	6.2
11	31.6	22.8	15.0
12	16.8	11.8	7.5
13	17.6	12.0	7.3

Year	Total cost ($ Million)	Present value of costs discounted at 3% ($ Million)	Present value of costs discounted at 7% ($ Million)
14	18.4	12.1	7.1
15	19.1	12.3	6.9
16	19.9	12.4	6.7
17	20.7	12.5	6.5
18	21.4	12.6	6.3
19	22.2	12.7	6.1
20	23.0	12.7	5.9
Total	331.0	238.8	164.7

The annualized costs and present value of the estimated costs over 20 years using 3 percent and 7 percent discount rates are given in Table 11.

TABLE 11. PRESENT VALUE OF COSTS AND ANNUALIZED COSTS OF THE ESTIMATED TOTAL COSTS CALCULATED OVER 20 YEARS

Discount rate	Present value of costs ($ Thousand)	Annualized costs ($ Thousand)
3%	238,826	15,597
7%	164,745	14,556

Cost Uncertainties

The cost estimates developed for this rule are built on a number of key assumptions:

- 4,200 miles of pipeline will begin to use an alternative MAOP in the first year after implementation of the rule, and an additional 700 miles of pipeline will begin to use an alternative MAOP in each succeeding year.
- Smart pigging will cost $4,160 per mile.
- Anomaly repairs will be made at the rate of 0.01 repairs per mile.
- The cost of repairing a pipeline anomaly will be $29,000.
- The remotely controlled valves will each cost $70,000.
- Twelve (12) additional remotely controlled valves will be needed per thousand miles of pipeline.
- Threat identification and evaluations cost $10,000 to prepare.
- Eighteen (18) threat identification and evaluations will need to be prepared in the first year and 3 will need to be prepared in each year thereafter.
- No updates to the threat identification and evaluations will be prepared.
- Patrolling rights-of-way will cost $100 per pipeline mile.
- Eleven (11) additional pipeline patrols will be needed annually.
- The cost of notification will be nominal.

These assumptions introduce uncertainties into the cost calculations. The impacts of these uncertainties on the costs of the rule are discussed below.

Impact of Mileage Estimates

The most important of the assumptions underlying the cost estimates are those relating to the mileage that is expected to begin using an alternative MAOP. The mileage estimates – 4,200 miles the first year and 700 miles each year thereafter – are used in the derivation of every cost estimate, with the exception of notification. The actual pipeline mileages adopting an alternative MAOP may vary from these estimates. Table 12 presents the costs that would result if the pipeline mileages were changed by plus or minus 50 percent. Table 13 gives the present values of the costs if the pipeline mileages were changed by plus or minus 50 percent.

TABLE 12. TOTAL COSTS BY YEAR WHEN MILEAGE IS CHANGED BY PLUS OR MINUS 50%

Year	Total cost by year when mileage is increased by 50% (Thousand)	Total cost by year when mileage is decreased by 50% (Thousand)
1	$57,694	$19,232
2	$9,017	$3,009
3	$10,172	$3,394
4	$11,327	$3,779
5	$12,482	$4,164
6	$13,637	$4,549
7	$14,792	$4,934
8	$15,947	$5,319
9	$17,102	$5,704
10	$18,257	$6,089
11	$45,619	$15,210
12	$25,240	$8,417
13	$26,395	$8,802
14	$27,550	$9,187
15	$28,705	$9,572
16	$29,860	$9,957
17	$31,015	$10,342
18	$32,170	$10,727
19	$33,325	$11,112
20	$34,480	$11,497
Total	**$494,786**	**$164,996**

TABLE 13. PRESENT VALUE OF THE ESTIMATED TOTAL OVER 20 YEARS WHEN MILEAGE IS CHANGED BY PLUS OR MINUS 50%

Discount rate	Present value when mileage is increased by 50% ($ Thousand)	Present value when mileage Is decreased by 50% ($ Thousand)
3%	357,017	119,055
7%	246,300	82,134

When the mileage is reduced to 2,100 miles in the first year, with 350 miles added in each subsequent year (i.e., by 50 percent), the annual total costs and the present values are essentially half of what was estimated using the 4,200 and 700 mileage values of the base case. When the mileage is increased to 6,300 miles in the first year with 1,150 miles in each subsequent year (i.e., by 50%), the annual total costs and the present values also increase by approximately 50 percent.

Adding 700 miles per year for 20 years may overstate the new pipeline mileage that would actually use an alternative MAOP. The addition of new pipeline might occur only over a shorter period, rather than every year for the 20 years following implementation of the rule. PHMSA estimates that approximately 3,500 miles of new gas transmission pipeline certified in the next 5 years would be operated at an alternative MAOP. Tables 14 and 15 present the annual total costs and present values that would result if only those 3,500 miles of new pipeline (with 700 miles added in each of the 5 years) were to use an alternative MAOP.

TABLE 14. TOTAL COST BY YEAR IF ADDITION OF 700 MILES PER YEAR ONLY OCCURS DURING THE FIRST 5 YEARS

Year	Total cost ($ Thousand)
1	38,282
2	5,948
3	6,718
4	7,488
5	8,258
6	7,700
7	7,700
8	7,700
9	7,700
10	7,700
11	26,970
12	11,403
13	11,403
14	11,403
15	11,403
16	11,403
17	11,403
18	11,403

Year	Total cost ($ Thousand)
19	11,403
20	11,403
Total	**234,791**

TABLE 15. PRESENT VALUE OF TOTAL COST OVER 20 YEARS IF ADDITION OF 700 MILES PER YEAR ONLY OCCURS DURING THE FIRST 5 YEARS

Discount rate	Present value ($ Thousand)
3%	176,741
7%	128,677

Adding 700 miles per year of new pipeline only during the first 5 years after implementation of the rule has a fairly dramatic impact on costs. The present value of the total costs is approximately 35 percent less than the base case estimate at the 3 percent discount rate. This is a significant change.

Impact of the Cost of Smart Pigging

The cost of smart pigging, $4,160, per mile, is based on an estimate previously provided to PHMSA by INGAA, an industry group representing interstate natural gas pipeline operators. Since INGAA should have a fairly good understanding of the costs of smart pigging for natural gas pipelines, and since the estimate was provided to PHMSA relatively recently, the uncertainties associated with the estimate are expected to be minor. The impacts of those uncertainties on the total costs of the rule are expected to be minimal.

Impact of Anomaly Repairs Per Mile

The base case assumes that 0.01 anomaly repairs per pipeline mile will be needed. This value is based on PHMSA's expectation that more stringent requirements concerning design, construction, and O&M will result in fewer anomaly repairs. Information on natural gas transmission pipelines indicates that they are experiencing 0.11 repairs per mile that need to be repaired immediately or within one year of discovery. This is a reasonable upper limit on the number of anomaly repairs that could be expected. PHMSA has hopes that the stringent requirements included in the rule could drive the repair rate down to where the rate per mile is approximately 0.00. This would a reasonable lower limit on the number of anomaly repairs that could be expected. Tables 16 and 17 present the total cost and present values when the anomaly repair rates are 0.11 per mile or 0.00 per mile.

TABLE 16. TOTAL COST BY YEAR WHEN THE ANOMALY REPAIR RATE IS INCREASED TO 0.11 PER MILE OR DECREASED TO 0.00 PER MILE

Year	Total cost by year when repair rate is increased to 0.11 per mile (Thousand)	Total cost by year when repair rate is decreased to 0.00 per mile (Thousand)
1	$48,612	$37,447
2	$6,008	$6,008
3	$6,778	$6,778
4	$7,548	$7,548
5	$8,318	$8,318
6	$9,088	$9,088
7	$9,858	$9,858
8	$10,628	$10,628
9	$11,398	$11,398
10	$12,168	$12,168
11	$30,409	$30,409
12	$18,853	$16,620
13	$19,623	$17,390
14	$20,393	$18,160
15	$21,163	$18,930
16	$21,933	$19,700
17	$22,703	$20,470
18	$23,473	$21,240
19	$24,243	$22,010
20	$25,013	$22,780
Total	**$358,210**	**$326,948**

TABLE 17. PRESENT VALUE OF THE ESTIMATED TOTAL COSTS OVER 20 YEARS WHEN THE ANOMALY REPAIR RATE IS INCREASED TO 0.11 PER MILE OR DECREASED TO 0.00 PER MILE

Discount rate	Present value when repair rate is increased to 0.11 per mile ($ Thousand)	Present value when repair Rate is decreased to 0.00 per mile ($ Thousand)
3%	259,235	235,835
7%	179,936	162,589

With an anomaly repair rate of 0.11 per mile, the present value of costs increases by approximately 8 percent at the 3 percent discount rate. With an anomaly repair rate of 0.00, the present value of costs decreases by approximately 2 percent at the 3 percent discount rate. The impact of changing the repair rate on costs would appear to be relatively small.

Impact of Cost of Anomaly Repairs

The base case assumes that the cost of repairing anomalies on gas transmission lines will be $29,000 per anomaly. Although this value is based on information obtained from Duke and INGAA, the actual average cost of repairing anomalies could be higher or lower than this value. In part, the value will depend on the value of the gas lost during repair. In the Duke/INGAA estimate, the value of the lost gas comprised over 40 percent of the total cost of the repair. Tables 18 and 19 present the total costs and present values when the cost of anomaly repairs is increased or decreased by 50 percent.

TABLE 18. TOTAL COST BY YEAR WHEN COST OF ANOMALY REPAIRS IS INCREASED OR DECREASED BY 50%

Year	Total cost by year when repair costs are increased by 50% (Thousand)	Total cost by year when repair costs are decreased by 50% (Thousand)
1	$38,970	$37,955
2	$6,008	$6,008
3	$6,778	$6,778
4	$7,548	$7,548
5	$8,318	$8,318
6	$9,088	$9,088
7	$9,858	$9,858
8	$10,628	$10,628
9	$11,398	$11,398
10	$12,168	$12,168
11	$30,409	$30,409
12	$16,925	$16,722
13	$17,695	$17,492
14	$18,465	$18,262
15	$19,235	$19,032
16	$20,005	$19,802
17	$20,775	$20,572
18	$21,545	$21,342
19	$22,315	$22,112
20	$23,085	$22,882
Total	**$331,216**	**$328,374**

TABLE 19. PRESENT VALUE OF ESTIMATED TOTAL COSTS OVER 20 YEARS WHEN COST OF ANOMALY REPAIRS IS INCREASED OR DECREASED BY 50%

Discount rate	Present value when repair costs are increased by 50% ($ Thousand)	Present value when repair Costs are decreased by 50% ($ Thousand)
3%	239,029	236,902
7%	164,957	163,380

Changing the cost of anomaly repairs has a minimal impact on total costs. The present value of cost changes by less than 1 percent at the 3 percent discount rate.

<u>Impact of Valve Cost</u>

For the base case costs, remotely controlled valves are assumed to cost $70,000 each. The actual cost of valves may be higher or lower than this. Tables 20 and 21 present the total costs and present values when valve costs are increased or decreased by 50 percent.

TABLE 20. TOTAL COST BY YEAR WHEN THE VALVE COST IS INCREASED OR DECREASED BY 50%

Year	Total cost by year when valve costs are increased by 50% (Thousand)	Total cost by year when valve costs are decreased by 50% (Thousand)
1	$40,226	$36,698
2	$6,302	$5,714
3	$7,072	$6,484
4	$7,842	$7,254
5	$8,612	$8,024
6	$9,382	$8,794
7	$10,152	$9,564
8	$10,922	$10,334
9	$11,692	$11,104
10	$12,462	$11,874
11	$30,703	$30,115
12	$17,117	$16,529
13	$17,887	$17,299
14	$18,657	$18,069
15	$19,427	$18,839
16	$20,197	$19,609
17	$20,967	$20,379
18	$21,737	$21,149
19	$22,507	$21,919
20	$23,277	$22,689
Total	**$337,140**	**$322,440**

TABLE 21. PRESENT VALUE OF TOTAL COST OVER 20 YEARS WHEN VALVE COSTS ARE INCREASED OR DECREASED BY 50%

Discount rate	Present value when valve cost is increased by 50% ($ Thousand)	Present value when valve cost is decreased by 50% ($ Thousand)
3%	243,763	232,161
7%	168,655	159,678

Changing the valve cost by 50 percent changes the present value of the total costs by approximately 2 percent at the 3 percent discount rate. The impact of changing the valve cost, therefore, would be relatively minor.

Impact of Number of Valves Installed

The base case assumes that 12 additional remotely controlled valves will be needed per thousand miles of pipeline. The impact of increasing the assumed number of values installed per mile by 50 percent will be identical to the impact of increasing the cost of the valves by 50 percent. The impact of decreasing the assumed number of valves installed by 50 percent will be identical to the impact of decreasing the cost of the valves by 50 percent. The total cost and present value when the cost of the valves is increased or decreased by 50 percent are presented in Tables 20 and 21. Based on the results presented in those tables, the impact of changing the number of valves installed is expected to be relatively minor.

Impact of Cost of Threat Identification and Evaluations

The base case assumes that threat identification and evaluations cost $10,000 to prepare. Tables 22 and 23 present the total costs and present value of those total costs when the cost of preparing a threat identification and evaluation is increased or decreased by 50 percent.

TABLE 22. TOTAL COST BY YEAR WHEN COST OF THREAT IDENTIFICATION AND EVALUATION IS INCREASED OR DECREASED BY 50%

Year	Total Cost by Year When Cost of Threat Identification and Evaluations Is Increased by 50% (Thousand)	Total Cost by Year When Cost of Threat Identification and Evaluations Is Decreased by 50% (Thousand)
1	$38,552	$38,372
2	$6,023	$5,993

Year	Total Cost by Year When Cost of Threat Identification and Evaluations Is Increased by 50% (Thousand)	Total Cost by Year When Cost of Threat Identification and Evaluations Is Decreased by 50% (Thousand)
3	$6,793	$6,763
4	$7,563	$7,533
5	$8,333	$8,303
6	$9,103	$9,073
7	$9,873	$9,843
8	$10,643	$10,613
9	$11,413	$11,383
10	$12,183	$12,153
11	$30,424	$30,394
12	$16,838	$16,808
13	$17,608	$17,578
14	$18,378	$18,348
15	$19,148	$19,118
16	$19,918	$19,888
17	$20,688	$20,658
18	$21,458	$21,428
19	$22,228	$22,198
20	$22,998	$22,968
Total	**$330,165**	**$329,415**

TABLE 23. PRESENT VALUE OF TOTAL COST OVER 20 YEARS WHEN COST OF THREAT IDENTIFICATION AND EVALUATION IS INCREASED OR DECREASED BY 50 PERCENT

Discount Rate	Present Value When Cost of Threat Identification and Evaluation Is Increased by 50% ($ Thousand)	Present Value When Cost of Threat Identification and Evaluation Is Decreased by 50% ($ Thousand)
3%	238,258	237,666
7%	164,395	163,937

Changing the threat identification and evaluation costs by plus or minus 50 percent has a negligible impact on the present value of the total costs at the 3 percent discount rate. Therefore, the impact of changing the threat identification and evaluation cost is relatively very minor.

Impact of Number of Threat Identification and Evaluations

In the base case, it is estimated that 18 threat identification and evaluations would be needed in the first year after implementation of the rule and three in every year thereafter. The actual number of threat identification and evaluations may be higher or lower than these estimates. The impact of increasing the assumed number of threat identification and evaluations by 50 percent will be identical to the impact of increasing the cost of threat identification and evaluations by 50 percent. The impact of decreasing the assumed number of threat identification and evaluations valves by 50 percent will be identical to the impact of decreasing the cost of threat identification and evaluations by 50 percent. The total cost and present value when the cost of threat identification and evaluations is increased or decreased by 50% are presented in Tables 22 and 23. Based on the results presented in those tables, the impact of changing the number of threat identification and evaluations is expected to be relatively minor.

Impact of No Threat Identification and Evaluation Updates

The base case cost estimate includes no estimates of the costs associated with updating the threat identification and evaluations. Updates will be required when conditions on, or surrounding, the pipelines change. There is no way to predict the nature of the changes. Consequently, there is no way to predict the costs of making those changes. At most, the cost of an update will be equal to the cost of the original threat identification and evaluation, but it should usually be significantly less. Given that the impact of preparing the original threat identification and evaluations is expected to be minimal, the impact of not including threat identification and evaluation updates in the cost analysis of the base case is also expected to be minimal.

Impact of Patrolling Cost

The base case estimates the cost of patrolling to be $100 per pipeline mile. The cost may be higher or lower than that estimate. Tables 24 and 25 present the total costs and present values when the cost of patrolling is increased or decreased by 50 percent.

TABLE 24. TOTAL COST BY YEAR WHEN COST OF PATROLLING IS INCREASED OR DECREASED BY 50 PERCENT

Year	Total cost by year when patrolling costs are increased by 50% ($ Thousand)	Total cost by year when patrolling costs are decreased by 50% ($ Thousand)
1	6,930	2,310
2	8,085	2,695
3	9,240	3,080
4	10,395	3,465
5	11,550	3,850
6	12,705	4,235
7	13,860	4,620

Year	Total cost by year when patrolling costs are increased by 50% ($ Thousand)	Total cost by year when patrolling costs are decreased by 50% ($ Thousand)
8	15,015	5,005
9	16,170	5,390
10	17,325	5,775
11	18,480	6,160
12	19,635	6,545
13	20,790	6,930
14	21,945	7,315
15	23,100	7,700
16	24,255	8,085
17	25,410	8,470
18	26,565	8,855
19	27,720	9,240
20	28,875	9,625
Total	**358,050**	**119,350**

TABLE 25. PRESENT VALUE OF TOTAL COST OVER 20 YEARS WHEN COST OF PATROLLING IS INCREASED OR DECREASED BY 50 PERCENT

Discount rate	Present value when patrolling cost is increased by 50% ($ Thousand)	Present value when patrolling cost is decreased by 50% ($ Thousand)
3%	321,147	154,778
7%	218,479	109,853

Changing the patrolling cost by plus or minus 50 percent changes the present value of the total costs by approximately 35 percent at the 3 percent discount rate. The impact associated with changing the patrol cost is therefore relatively significant.

Impact of the Cost of Notification and Recordkeeping

The rule requires an operator to notify PHMSA, and state pipeline safety regulators exercising jurisdiction, when it elects to establish an alternative MAOP. Operators are required to furnish evaluation reports, prepare notification letters, disseminate public notices, and keep records.

PHMSA labor costs calculations are based on the following assumptions:

- PHMSA estimates that 18 transmission operators will elect to establish alternative MAOP the first year, and three additional operators will opt to operate under alternative MAOP in successive year. This estimate is derived from the number of reports PHMSA received in 2006. In 2006 PHMSA received 1,393 reports covering 320,532 miles of gas transmission and gathering pipelines. On average each report covered 230 miles of pipeline (320,532 / 1,393). If each report covers, on average, one pipeline, PHMSA expects that 18 pipeline operators will account for the 4,200 miles of pipeline adopting an alternative MAOP in the first year (4,200 / 230). Similarly three operators will account for the 700 miles of additional pipeline that will adopt alternative MAOP in successive years (700 / 230).

- A compliance officer will prepare notification safety related documents and public awareness notices required under Sections 192.112, 192.328 and 192.620. Compliance officers in the natural gas industry earn, on average, $26.50 per hour with a fully loaded rate of approximately $40.00 ($26.50 * 1.50).[35]
- A chief executive officer earning, on average, $89.61 per hour with a fully loaded rate of approximately $134.00 ($89.61 * 1.50) will verify and sign notifications letters.[36]
- Health and safety engineers earning, on average, $36.25 per hour with a fully loaded rate of approximately $54 per hour ($36.25 * 1.50) will prepare the threat identification and evaluations described under Section 192.620.[37]
- Currently PHMSA requires operators to submit annual reports. Those reports take 12 hours to prepare. Preparing the required safety testing notifications and public awareness notices is not expected to be any more complicated or time consuming than preparing an annual report and would not exceed 12 hours per notification.
- PHMSA estimates that notification letters may be prepared in one-half hour (30 minutes).
- The notification letter must be signed by a senior executive officer. PHMSA estimates that it may take a senior pipeline executive 10 minutes to review and sign it.
- Bases on industry estimates, PHMSA expects each threat identification and evaluation will require 150 hours of labor to prepare.[38]

Information Collection Burden Reduction - PHMSA believes that the alternative MAOP regulation will reduce the number of reportable incidents. If the incidents are reduced then incident reports for those avoided incidents will also decrease. Because of the uncertainty involved the reduction of incident reports and their associated time burden is not included in the PRA analysis. However, it should be noted that besides the large benefits to human safety and reduced property damage from reduced incidents, the regulation will also likely produce a nominal savings in information collection burden.

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[35] Bureau of Labor and Statistics hourly mean pay rate data forgas transportation industry NAICS 486200 - Pipeline Transportation of Natural Gas workers. May 2007 National Industry-Specific Occupational Employment and Wage Estimates. http://www.bls.gov/oes/current/naics4_486200.htm
[36] Ibid.
[37] Bureau of Labor and Statistics hourly mean pay rate data forgas transportation industry NAICS 486200 - Pipeline Transportation of Natural Gas workers. May 2007 National Industry-Specific Occupational Employment and Wage Estimates. http://www.bls.gov/oes/current/naics4_486200.htm.
[38] Communication between M. Dwayne Burton, KinderMorgan, and Paul Zebe, Volpe Center, August 3, 2007.

Notification Costs - PHMSA estimates that the cost of preparing and issuing safety related notifications and public awareness notices is $8,640 ($40* 12hours* 18 notifications) the first year and $1,440 ($40* 12 hours* 3 notifications) in successive years.

PHMSA estimates the cost of preparing a notification letter, having it signed, and sending it to the Agency is $720 the first-year (18 notifications * 30 minutes* $40) and $60 each successive years (3 notifications * 30 minutes * $40). The cost for the senior official to review and sign the notification is estimated at $ 402 (18 notifications * $134 * .167 hours) the first-year and $ 67 (3 * $134 * .167 hours) in successive years.

PHMSA acknowledges that there may be some additional nominal cost to operators for storage and filing, depending on whether records are kept electronically or on paper, the length of time records are kept (i.e., the life of the pipeline), the volume, and how records are packaged. Assuming that operators store approximately (within their facilities) one cubic foot of records (at $23.00 per cubic foot) each, PHMSA estimates that it would cost each operator $23 per year to store and maintain the required paper records.

Threat Identification and Evaluation Costs - Each threat identification and evaluation prepared by a health and safety engineer is expected to cost $8,100 ($54 * 150 burden hours) per identification and evaluation. In the first year the total cost of the threat identification and evaluations are estimated to be $145,800 ($8,100 * 18 threat identification and evaluations). In subsequent years the total cost is expected to drop to $24,300 ($8,100 * 3 threat identification and evaluations).

Summary of Costs - The cost associated with notification and threat identification and evaluations requirements is estimated at approximately $155,502 in the first-year and $25,867 in successive years.

Summary

Based on this analysis of the regulation, there will be an estimated 2,928 total annual burden hours attributable to the notification and recordkeeping requirements in the first year. In following years, the annual burden is expected to decrease to 489 hours. The associated cost of these annual burden hours is $155,502 in year one, and $25,867 thereafter. Since document preparation could be much lower than the 12 hours allowed on the preparation of evaluation reports by PHMSA in calculating the burden, costs may be lower than projected.

Impact Summary

In summary, changes in mileage, patrolling costs, and the number of patrols all appear to have noteworthy impacts on the rule's cost. The impacts on costs attributable to changing other assumptions are expected to be relatively minor.

6.4 Comparison of Benefits and Costs

The benefits resulting from the rule are estimated to be $103.6 million per year, consisting of $49.0 million in annual benefits from fuel cost savings and $54.6 million in annual one-time benefits associated with new pipeline reduced capital expenditures.

The costs of the rule, by year, are presented in Table 9. In total, the costs of the rule are expected to be approximately $38 million in the 1st year, go from approximately $6 million in the 2nd year to $12 million in the 10th year, be approximately $32 million in the 11th year, and then go from approximately $16 million in the 12th year to $23 million in the 20th year.

TABLE 26. PRESENT VALUE OF THE BENEFITS OF THE RULE CALCULATED OVER 20 YEARS ($Million)

Benefit Items	Annual Benefits	Present Value at 3% Discount	Present Value at 7% Discount
Reduced Fuel Costs Savings	49.0	729	519
Reduced Capital Expenditures	54.6	812	578
Total Benefits	103.6	1,541	1,097

Table 27. PRESENT VALUE OF THE COSTS OF THE RULE CALCULATED OVER 20 YEARS ($Million)

Cost Item	Present Value at 3% Discount	Present Value at 7% Discount
Baseline Internal Inspections	28.3	27.2
Additional Internal Inspections	29.0	17.3
Anomaly Repairs	3.0	2.2
Remotely Controlled Valves	11.6	9.0
Threat Identification and Evaluations	.6	.5
Patrolling	166.4	108.6
Total Costs	238.8	164.7

TABLE 28. NET BENEFITS OF THE RULE
($ Million)

Discount rate	Present Value of the Benefits Calculated Over 20 Years	Present Value of the Costs Calculated over 20 Years	Net benefits
3%	1,541	239	1,302
7%	1,098	165	933

As can be seen from Table 28, the present value of the estimated benefits of the rule would be expected to significantly exceed the present value of the estimated costs. The present value net benefits of the rule are expected to be positive: $1.3 billion at the 3 percent discount rate and $0.9 billion at the 7 percent discount rate. Since there are positive net benefits, PHMSA has concluded the rule is in the public interest.

It might be argued that the rule effectively has much smaller benefits and costs than those estimated in this analysis, relative to the ability of pipeline operators to gain special permits that would put in place many of the same requirements of these rules. Those upgrading their pipelines under the rule may be likely to apply for special permits absent the rule. Consequently, a level of benefits tied to the alternative MAOP could eventually be achieved even without the rule. Furthermore, the costs to operators of using the alternative method to establish MAOP under the rule would be similar to those incurred to meet the requirements mandated by PHMSA for special permits. The primary benefit of the rule, if this argument is accepted, would be that it would relieve PHMSA of the cost and resource burden associated with evaluating and approving or rejecting special permits. Even if one accepts this argument, however, PHMSA has concluded that the more efficient process outlined in this rule will likely lead to a faster deployment of these new requirements and therefore, will likely accelerate the realization of the net benefits associated with adopting an alternative MAOP.

6.5 Benefit and Cost Uncertainties

A number of assumptions were made in the calculation of the benefits and costs of the rule. Those assumptions could potentially impact whether the net benefits of the rule are positive or negative. Present value estimates have been calculated for various benefit and cost assumption alternatives. Table 29 below presents the net benefits for those alternatives when evaluated over 20 years with a 3 percent discount rate (the conclusions drawn using the 3 percent discount rate will be similar to those drawn using a 7 percent rate). Table 24 also includes the benefit and cost base cases for comparison with alternatives.

TABLE 29. NET PRESENT VALUE OF THE BENEFITS FOR THE BASE CASE AND FOR BENEFIT AND COST ALTERNATIVES AT THE 3% DISCOUNT RATE

COST ALTERNATIVES	Base case	BENEFIT ALTERNATIVES (Million) Mileage increased by 50%	Mileage decreased by 50%	Only 700 miles of new pipeline per year for first 5 years after rule goes into effect	Fuel cost savings increased by 50%	Fuel cost savings decreased by 50%	Capital expenditure savings increased by 50%	Capital expenditure savings decreased by 50%
Base case	$1,302	-	-	-	$1,906	$1,177	$1,947	$1,135
Mileage increased by 50%	-	$1,955	-	-	-	-	-	-
Mileage decreased by 50%	-	-	$652	-	-	-	-	-
Only 700 miles of new pipeline per year for first 5 years after rule goes into effect	-	-	-	$814	-	-	-	-
Number of repairs=0.00	$1,282	-	-	-	$1,647	$918	$1,688	$876
Number of repairs=0.11	$1,305	-	-	-	$1,670	$941	$1,711	$899
Repair costs increased by 50%	$1,302	-	-	-	$1,667	$938	$1,708	$896
Repair costs decreased by 50%	$1,304	-	-	-	$1,669	$940	$1,710	$898
Valve costs increased by 50%	$1,297	-	-	-	$1,662	$933	$1,703	$891
Valve costs decreased by 50%	$1,309	-	-	-	$1,674	$945	$1,715	$903
Threat Cost +50%	$1,303				$1,668	$939	$1,709	$897
Threat Cost -50%	$1,303				$1,668	$939	$1,709	$897
Threat Id and Evals. +50%	$1,303				$1,668	$939	$1,709	$897
Threat Id and Evals. -50%	$1,303				$1,668	$939	$1,709	$897
Patrolling costs increased by 50%	$1,220	-	-	-	$1,585	$856	$1,626	$814
Patrolling costs decreased by 50%	$1,386	-	-	-	$1,751	$1,022	$1,792	$980
Number of additional patrols=6	$1,379	-	-	-	$1,744	$1,015	$1,785	$973

Table Key: "-": Mileage assumptions of benefit and cost alternatives are inconsistent with each other, so no net benefits were calculated.

There are a total of 73 benefit/cost combinations with a calculated net present value of benefits in Table 27. In all cases, the present value of benefits exceeds the present value of costs. That is, there are positive net benefits. Those net benefits range from $652million to $1,947million. Under all benefit/cost combinations evaluated, the implementation of the rule would be in the public interest

7. SUMMARY AND CONCLUSIONS

PHMSA revises the Federal pipeline safety regulations to allow natural gas transmission operators to raise the MAOP for certain pipelines (1) constructed of steel pipe manufactured using modern steel chemistry and rolling practices and standards, and (2) inspected and tested to more rigorous standards. Under the rule, this alternative MAOP, by class location, would be:

- Class 1: Greater than 72% of SMYS but less than or equal to 80% of SMYS
- Class 2: Greater than 60% of SMYS but less than or equal to 67% of SMYS
- Class 3: Greater than 50% of SMYS but less than or equal to 56% of SMYS
- Class 4: No alternative MAOP for class 4 locations.

This rule mandates no action by the gas transmission pipeline operators. As a result of the rule, however, 3,500 miles of existing natural gas transmission pipeline are expected to be uprated to an alternative MAOP. Furthermore, the rule is expected to result in the operators of an additional 700 miles of new pipeline electing to use an alternative MAOP each year in the future.

The quantified benefits resulting from the rule are estimated for the first year after the rule goes into effect to be $49.0 million of annually recurring benefits (these benefits are realized in the first and in each subsequent year) and $54.6 million of one-time benefits. For the 700 miles of new pipeline added in each subsequent year, quantified benefits are estimated to be $54.6 million each year from savings in capital expenditures. The quantified benefits consist of:

- Fuel cost savings of existing pipelines
- Capital expenditure savings on pipe for new pipelines.

The costs of the rule are estimated to be $38.2 million in the 1st year, go from $6.0 million in the 2nd year to $12.1 million in the 10th year, be $31.6 million in the 11th year, and then go from $16.1 million in the 12th year to $23.0 million in the 20th year. The costs attributable to the rule are most likely to be incurred by operators for:

- Performing baseline internal inspections
- Performing additional internal inspections
- Performing anomaly repairs
- Installing remotely controlled valves on either side of high consequence areas (HCAs)
- Preparing threat identification and evaluation
- Patrolling pipeline rights-of-way
- Notifying PHMSA.

The present value of the quantified benefits of the rule is estimated to be $1,541 million calculated over 20 years using a 3 percent discount rate and $1,098 million calculated over 20 years using a 7 percent discount rate. The present value of the estimated costs of the rule would be expected to be approximately $239 million over 20 years using a 3 percent discount rate and $165 million over 20 years using a 7 percent discount rate. The quantified benefits of the rule exceed the costs. Net benefits are approximately $1.3 billion at the 3 percent discount rate and $0.9 billion at the 7 percent discount rate. The rule is expected to be in the public interest.

The quantified benefits, it should be noted, do not capture the full benefits of the rule. Expected benefits of the rule that cannot be readily quantified include:

- Reductions in incident consequences
- Increases in pipeline capacity
- Increases in line pack
- Reductions in capital expenditures on compressors for existing pipelines
- Reductions in adverse environmental impacts
- Other expected benefits.

PHMSA believes that these non-quantified benefits significantly increase the spread between the benefits and costs associated with the rule.

Because of potentially significant uncertainties in the benefit and cost estimates, alternative benefit and cost estimates were developed and alternative net benefits were calculated. The net benefits for all alternatives were positive. This would appear to support the conclusion that the rule is in the public interest.