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

DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Part 192

[Docket No. PHMSA–2005–23447]

RIN 2137–AE25

Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Final rule.

SUMMARY: PHMSA is amending the pipeline safety regulations to prescribe safety requirements for the operation of certain gas transmission pipelines at pressures based on higher operating stress levels. The result is an increase of maximum allowable operating pressure (MAOP) over that currently allowed in the regulations. Improvements in pipeline technology assessment methodology, maintenance practices, and management processes over the past twenty-five years have significantly reduced the risk of failure in pipelines and necessitate updating the standards that govern the MAOP. This rule will generate significant public benefits by reducing the number and consequences of potential incidents and boosting the potential capacity and efficiency of pipeline infrastructure, while promoting rigorous life-cycle maintenance and investment in improved pipe technology.

DATES: *Effective Date:* This final rule takes effect November 17, 2008.

Incorporation by Reference Date: The incorporation by reference of a certain publication listed in this rule is approved by the Director of the Federal Register as of November 17, 2008.

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SUPPLEMENTARY INFORMATION:

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A. Purpose of the Rulemaking

PHMSA published a Notice of Proposed Rulemaking (NPRM) on March 12, 2008 (73 FR 13167), to establish standards under which certain natural or other gas (gas) transmission pipelines would be allowed to operate at higher maximum allowable operating pressure (MAOP). The proposed changes were made possible by dramatic improvements in pipeline technology and risk controls over the past 25 years. The current standards for calculating MAOP on gas transmission pipelines were adopted in 1970, in the original pipeline safety regulations promulgated under Federal law. Almost all risk controls on gas transmission pipelines have been strengthened in the intervening years, beginning with the introduction of improved manufacturing, metallurgy, testing, and assessment tools and standards. Pipe manufactured and tested to modern standards is far less likely to contain defects that can grow to failure over time than pipe manufactured and installed a generation ago. Likewise, modern maintenance practices, if consistently followed, significantly reduce the risk that corrosion, or other defects affecting pipeline integrity, will develop in installed pipelines. Most recently, operators' development and implementation of integrity management programs have increased understanding about the condition of pipelines and how to reduce pipeline risks. In view of these developments, PHMSA concludes that certain gas transmission pipelines can be safely and reliably operated at pressures above current Federal pipeline safety design limits. With appropriate conditions and controls, permitting operation at higher pressures will increase energy capacity and efficiency without diminishing system safety.

Currently, PHMSA has granted special permits on a case-by-case basis to allow operation of particular pipeline segments at a higher MAOP than currently allowed under the existing design requirements. These special permits, that have been granted, have been limited to operation in Class 1, 2, and 3 locations and conditioned on demonstrated rigor in the pipeline's design and construction and the operator's performance of additional safety measures. Building on the record of success developed in the special permit proceedings, PHMSA is codifying the conditions and limitations of the special permits into standards of general applicability.

B. Background

B.1. Current Regulations

The design factor specified in § 192.105 restricts the MAOP of a steel gas transmission pipeline based on stress levels and class location. For most steel pipelines, the MAOP is defined in § 192.619 based on design pressure calculated using a formula, found at § 192.111, which includes the design factor. The regulations establish four classifications based on population density, ranging from Class 1 (undeveloped, rural land) through Class 4 (densely populated urban areas). In sparsely populated Class 1 locations, the design factor specified in § 192.105 restricts the stress level at which a pipeline can be operated to 72 percent of the specified minimum yield strength (SMYS) of the steel. The operating pressures in more populated Class 2 and Class 3 locations are limited to 60 and 50 percent of SMYS, respectively. Paragraph (c) of § 192.619 provides an exception to this calculation of MAOP for pipelines built before the issuance of the Federal pipeline safety standards. A pipeline that is ''grandfathered'' under this section may be operated at a stress level exceeding 72 percent of SMYS if it was operated at that pressure for five years prior to July 1, 1970.

Part 192 also prescribes safety standards for designing, constructing, operating, and maintaining steel pipelines used to transport gas. Although these standards have always included several requirements for initial and periodic testing and inspection, prior to 2003, part 192 contained no Federal requirements for internal inspection of existing pipelines. Internal inspection is performed using a tool known as an ''instrumented pig'' (or ''smart pig''). Many pipelines constructed before the advent of this technology cannot accommodate an instrumented pig and, accordingly, cannot be inspected internally. Beginning in 1994, PHMSA required operators to design new pipelines so that they could accommodate instrumented pigs, paving the way for internal inspection (59 FR 17281; Apr. 12, 1994).

In December 2003, PHMSA adopted its gas transmission integrity management rule, requiring operators to develop and implement plans to extend additional protections, including internal inspection, to pipelines located in ''high consequence areas'' (HCAs) (68 FR 69816). Integrity management programs, as required by subpart O of part 192, include threat assessments, both baseline and periodic internal inspection, pressure testing, or direct assessment (DA), and additional measures designed to prevent and mitigate pipeline failures and their consequences. AN HCA, as defined in § 192.903, is a geographic territory in which, by virtue of its population density and proximity to a pipeline, a pipeline failure would pose a higher risk to people. In addition to class location, one of the criteria for identifying an HCA is a potential impact circle surrounding a pipeline. The calculation of the circle includes a factor for the MAOP, with the result that a higher MAOP results in a larger impact circle.

B.2. Evolution in Views on Pressure

Absent any defects, and with proper maintenance and management practices, steel pipe can last for many decades in gas service. However, the manufacture of the steel or rolling of the pipe can introduce flaws. In addition, during construction, improper backfilling can damage the pipe and pipe coating. Over time, damaged coating unchecked can allow corrosion to continue and cause leaks. Excavation-related damage can produce an immediate pipeline failure or leave a dent or coating damage that could grow to failure over time.

The regulations on MAOP in part 192 have their origin in engineering standards developed in the 1950s, when industry had relatively limited information about the material properties of pipe and limited ability to evaluate a pipeline's integrity during its operating lifetime. Early pipeline codes allowed maximum operating pressures to be set at a fixed amount under the pressure of the initial strength test without regard to SMYS. Pipeline engineers developing consensus standards looked for ways to lengthen the time before defects initiated during manufacture, construction, or operation could grow to failure. Their solutions focused on tests done at the mill to evaluate the ability of the pipe to contain pressure during operation. They added an additional factor to the hydrostatic test pressure of the mill test. At the time during the 1950's, the consensus standard, known as the B31.8 Code, used this conservative margin of safety for gas pipe design. A 25 percent margin of safety translated into a design factor limiting stress level to 72 percent of SMYS in rural areas. Specifically, the MAOP of 72 percent of SMYS comes from dividing the typical maximum mill test pressure of 90 percent of SMYS by 1.25. When issuing the first Federal pipeline safety regulations in 1970, regulators incorporated this design factor, as found in the 1968 edition of the B31.8 Code, into the requirements for determining the MAOP.

Even as the Federal regulations were being developed, some technical support existed for operation at a higher stress level, provided initial strength testing resulted in operators removing defects. In 1968, the American Gas Association published Report No. L30050 entitled *Study of Feasibility of Basing Natural Gas Pipeline Operating Pressure on Hydrostatic Test Pressure* prepared by the Battelle Memorial Institute. The research study concluded that:

- It is inherently safer to base the MAOP on the test pressure, which demonstrates the actual in-place yield strength of the pipeline, than to base it on SMYS alone.
- High pressure hydrostatic testing is able to remove defects that may fail in service.
- Hydrostatic testing to actual yield, as determined with a pressure-volume plot, does not damage a pipeline.

The report specifically recommended setting the MAOP as a percentage of the field test pressure. In particular, it recommended setting the MAOP at 80 percent of the test pressure when the minimum test pressure was 90 percent of SMYS or higher. Although the committee responsible for the B31.8 Code received the report, the committee deferred consideration of its findings at that time because the Federal regulators had already begun the process to incorporate the 1968 edition of the B31.8 Code into the Federal pipeline safety standards.

More than a decade later, the committee responsible for development of the B31.8 Code, now under the auspices of the American Society of Mechanical Engineers (ASME), revisited the question of the design factor it had deferred in the late 1960s. The committee determined pipelines could operate safely at stress levels up to 80 percent of SMYS. ASME updated the design factors in a 1990 addendum to the 1989 edition of the B31.8 Code, and they remain in the current edition. Although part 192 incorporates parts of the B31.8 Code by reference, it does not incorporate the updated design factors. With the benefit of operating experience with pipelines, it seems clear that operating pressure plays a less critical role in pipeline integrity and failure consequence than other factors within the operator's control.

By any measure, new technologies and risk controls have had a far greater impact on pipeline safety and integrity. A great deal of progress has occurred in the manufacture of steel pipe and in its initial inspection and testing. Technological advances in metallurgy and pipe manufacture decrease the risk of incipient flaws occurring and going undetected during manufacture. The detailed standards now followed in steel and pipe manufacturing provide engineers considerable information about their material properties. Toughness standards make new steel pipe more likely to resist fracture and to survive mechanical damage. Knowledge about the material properties allows engineers to predict how quickly flaws, whether inherent or introduced during construction or operation, will grow to failure under known operating conditions.

Initial inspection and hydrostatic testing of pipelines allow operators to discover flaws that have occurred prior to operation, such as during transportation or construction. They also serve to validate the integrity of the pipeline before operation. Initial pressure testing causes longitudinal and some other flaws introduced during manufacture, transportation, or construction to grow to the point of failure. Initial pressure testing detects all but one type of manufacturing or construction defect that could cause failure in the near-term. The sole type of defect that pressure testing may not identify, a flaw in a girth weld, is detectable through pre-operational non-destructive testing, which is required in this rule.

The most common defects initiated during operation are caused by mechanical damage or corrosion. Improvements in technology have resulted in internal inspection techniques that provide operators a significant amount of information about defects. Although there is significant variance in the capability of the tools used for internal inspections, each provides the operator information about flaws in the pipeline that an operator would not otherwise have. An operator can then examine these flaws to determine whether they are defects requiring repair. In addition, internal inspections with in-line inspection (ILI) devices, unlike pressure testing, are not destructive and can be done while the pipeline is in operation. Initial internal inspection establishes a baseline. Operators can use subsequent internal inspections at appropriate intervals to monitor for changes in flaws already discovered or to find new flaws requiring repair or monitoring. Internal inspections, and other improved life-cycle management practices, increase the likelihood operators will detect any flaws that remain in the pipe after initial inspection and testing, or that develop after construction, well before the flaws grow to failure.

B.3. History of PHMSA Consideration

Although the agency had never formally revisited its part 192 MAOP standards, prior to this rulemaking, developments in related arenas have increasingly set the stage for changes to those standards. Grandfathered pipelines have operated successfully at higher stress levels in the United States during more than 35 years of Federal safety regulation. Many of these grandfathered pipelines have operated at higher stress levels for more than 50 years without a higher rate of failure. We have also been aware of pipelines outside the United States operating successfully at the higher stress levels permitted under the ASME standard. A technical study published in December 2000 by R.J. Eiber, M. McLamb, and W.B. McGehee, *Quantifying Pipeline Design at 72% SMYS as a Precursor to Increasing the Design Stress Level*, GRI–00/0233, further raised interest in the issue.

In connection with our issuance of the 2003 gas transmission integrity management regulations, PHMSA announced a policy to grant ''class location'' waivers (now called special permits) to operators demonstrating an alternative integrity management program for the affected pipeline. A ''class location'' waiver allows an operator to maintain current operating pressure on a pipeline following an increase in population that changes the class location. Absent a waiver, the operator would have to reduce pressure or replace the pipe with thicker walled pipe. PHMSA held a meeting on April 14–15, 2004, to discuss the criteria for the waivers. In a notice seeking public involvement in the process (69 FR 22116; Apr. 23, 2004), PHMSA announced:

> Waivers will only be granted when pipe condition and active integrity management provides a level of safety greater than or equal to a pipe replacement or pressure reduction.

A second notice (69 FR 38948; June 29, 2004) announced the criteria. The criteria included the use of high quality manufacturing and construction processes, effective coating, and a lack of systemic problems identified in internal inspections Although the class location special permits/waivers do not address increases in stress levels *per se,* the risk management approach developed in those cases takes account of operating pressure and addresses many of the same concerns. The same risk management approach, and many of the specific criteria applied in the class location waivers, guided PHMSA's handling of the special permits discussed below and, ultimately, this rule.

Beginning in 2005, operators began addressing the issue of stress level directly with requests that PHMSA allow operation at the MAOP levels that the ASME B31.8 Code would allow. With the increasing interest, PHMSA held a public meeting on March 21, 2006, to discuss whether to allow increased MAOP consistent with the updated ASME standards. PHMSA also solicited technical papers on the issue. Papers filed in response, as well as the transcript of the public meeting, are in the docket for this rulemaking. Later in 2006, PHMSA again sought public comment at a meeting of its advisory committee, the Technical Pipeline Safety Standards Committee (TPSSC). The transcript and briefing materials for the June 28, 2006, meeting are in the docket for the advisory committee, Docket ID PHMSA–RSPA–1998–4470–204, 220. This docket can be found at *http://www.regulations.gov*. Comments and papers written during the period these efforts were undertaken overwhelmingly supported examining increased MAOP as a way to increase energy efficiency and capacity while maintaining safety.

B.4. Safety Conditions in Special Permits

In 2005, operators began requesting waivers, now called special permits, to allow operation at the MAOP levels that the ASME B31.8 Code would allow. In some cases, operators filed these requests at the same time they were seeking approval from the Federal Energy Regulatory Commission (FERC) to build new gas transmission pipelines. In other cases, operators sought relief from current MAOP limits for existing pipelines that had been built to more rigorous design and construction standards.

In developing an approach to the requests, PHMSA examined the operating history of lines already operated at higher stress levels. Canadian and British standards have allowed operation at the higher stress levels for some time. The Canadian pipeline authority, which has allowed higher stress levels since 1973, reports the following regarding pipelines operating at stress levels higher than 72 percent of SMYS:

- About 6,000 miles of pipelines on the Alberta system, ranging from six to 42 inches in diameter, were installed or upgraded between the early 1970s and 2005;
- About 4,500 miles of pipelines on the Mainline system east of the Alberta-Saskatchewan border, ranging from 20 to 42 inches in diameter, were installed or upgraded between the early 1970s and 2005; and,

• More than 600 miles in the Foothills Pipe Line system, ranging from 36 to 40 inches in diameter, were installed between 1979 and 1998.

In the United Kingdom, about 1,140 miles of the Northern pipeline system have been uprated to operate at higher stress level in the past ten years. Accident rates for pipelines in these countries have not indicated a measurable increased risk from operation at these higher operating stress levels.

In the United States, some 5,000 miles of gas transmission lines have MAOPs that were grandfathered under § 192.619(c), when the Federal pipeline safety regulations were adopted in the early 1970s, continue to operate at stress levels higher than 72 percent of SMYS. After some accidents caused by corrosion on grandfathered pipelines, PHMSA considered whether to remove the exception in § 192.619(c). In 1992, PHMSA decided to continue to allow operation at the grandfathered pressures (57 FR 41119; Sept. 9, 1992). PHMSA based its decision on the operating history of two of the operators whose pipelines contained most of the mileage operated at the grandfathered pressures. PHMSA noted the incident rate on these pipelines, operated at stress levels above 72 percent of SMYS, was between 10 percent and 50 percent of the incident rate of pipelines operated at the lower pressure. Texas Eastern Gas Pipeline Company (now Spectra Energy), the operator of many of the grandfathered pipelines, attributed the lower incident rate to aggressive inspection and maintenance. This included initial hydrostatic testing to 100 percent of SMYS, internal inspection, visual examination of anomalies found during internal inspection, repair of defects, and selective pressure testing to validate the results of the internal inspection. Internal inspection was not in common use in the industry prior to the 1980s. PHMSA's statistics show these pipelines continue to have an equivalent safety record when compared with pipelines operating according to the design factors in the pipeline safety regulations.

PHMSA also considered technical studies and required companies seeking special permits to provide information about the pipelines' design and construction and to specify the additional inspection and testing to be used. PHMSA also considered how to handle findings that could compromise the long-term serviceability of the pipe. PHMSA concluded that pipelines can operate safely and reliably at stress levels up to 80 percent of SMYS if the pipeline has well-established metallurgical properties and can be managed to protect it against known threats, such as corrosion and mechanical damage.

Early and vigilant corrosion protection reduces the possibility of corrosion occurring. At the earliest stage, this includes care in applying a protective coating before transporting the pipe to the right-of-way. With the newer coating materials and careful application, coating provides considerable protection against external corrosion and facilitates the application of induced current, commonly called cathodic protection, to prevent corrosion from developing at any breaks that may occur in the coating. Regularly monitoring the level of protection and addressing any low readings will detect and correct conditions that can cause corrosion at an early stage. Vigilant corrosion protection includes close attention to operating conditions that lead to internal corrosion, such as poor gas quality. In addition, for new pipelines, operators' compliance with a rule issued last year requiring greater attention to internal corrosion protection during design and construction (72 FR 20059; Apr. 23, 2007) will prevent internal corrosion. Finally, corrosion protection includes internal inspection and other assessment techniques for early detection of both internal and external corrosion.

One of the major causes of serious pipeline failure is mechanical damage caused by outside forces, such as an equipment strike during excavation activities. Burying the pipeline deeper, increased patrolling, and additional line marking help prevent the risk that excavation will cause mechanical damage. Further, enhanced pipe properties increase the pipe's resistance to immediate puncture from a single equipment strike. Improved toughness increases the ability of the pipe to withstand mechanical damage from an outside force and may also limit any failure consequences to leaks rather than ruptures. This toughness usually allows time for the operator to detect the damage during internal inspection well before the pipe fails.

To evaluate each request for a special permit, PHMSA established a docket and sought public comment on the request. We received several public comments, most in response to the first special permits considered. Many of the comments supported granting the special permits. Those who were not supportive may have underestimated the significance of the safety upgrades required for the special permits. A few commenters raised technical concerns. Among these were questions about the impact of rail crossings and blasting activities in the vicinity of the pipeline. The special permits did not change the current requirements where road crossings exist and added a requirement to monitor activities, such as blasting, that could impact earth movement. Some commenters expressed concern about the impact radius of the pipeline operating at a higher stress level. PHMSA included supplemental safety criteria to address the increased radius. The remainder of the comments addressed concerns, such as compensation or aesthetics, which were outside the scope of the special permits. PHMSA special permits do not address issues on siting, which are governed by the FERC.

PHMSA expects to issue seven special permits, and possibly more, in response to these requests. In each case, PHMSA has provided oversight to confirm the line pipe is, or will be (for pipe yet to be constructed), as free of inherent flaws as possible, that construction and operation do not introduce flaws, and that any flaws are detected before they can fail. PHMSA accomplishes this by imposing a series of conditions on the grant of special permits. The conditions imposed as part of the special permits are designed to address the potential additional risk involved in operating the pipeline at a higher stress level. A proposed pipeline must be built to rigorous design and construction standards, and the operator requesting a special permit for an existing pipeline must demonstrate that the pipeline was built to rigorous design and construction standards. These additional design and construction standards focused on producing a high quality pipeline that is free from inherent defects that could grow more rapidly under operation at a higher stress level and is more resistant to expected operational risks. In addition, PHMSA requires the operator of a pipeline receiving a special permit to comply with operation and maintenance (O&M) requirements that exceed current pipeline safety regulations. These additional O&M and integrity management requirements focused on the potential for corrosion and mechanical damage and on detecting defects before the defects can grow to failure.

B.5. Codifying the Special Permit Standards

This rule puts in place a process for managing the life-cycle of a pipeline operating at a higher stress level based on our experience with the special permits. Integrity management focuses on managing and extending the service life of the pipeline. Life-cycle management goes beyond the operations and maintenance practices, including integrity management, to address steel production, pipeline manufacture, pipeline design, and installation.

Industry experience with integrity management demonstrates the value of life-cycle management. Through baseline assessments in integrity management programs, gas transmission operators identified and repaired 2,883 defects in the first three years of the program (2004, 2005, and 2006). More than 2,000 of these were discovered in the first two years as operators assessed their highest risk, generally older, pipelines. In a September 2006 report, GAO–09–946, the Government Accountability Office noted this data as an early indication of improvement in pipeline safety. In order to qualify for operation at higher stress levels under this rule, pipelines will be designed and constructed under more rigorous standards. Baseline assessment of these lines will likely uncover few defects, but removing those few defects will result in safer pipelines. In addition, the results of the baseline assessment will aid in evaluating anomalies discovered during future assessments.

This rule, based on the terms and conditions of the special permits allowing operation at higher stress levels, imposes similar terms and conditions and limitations on operators seeking to apply the new rule. The terms and conditions, which include meeting design standards that go beyond current regulation, address the safety concerns related to operating the pipeline at a higher stress level. PHMSA will step up inspection and oversight of pipeline design and construction, in addition to review and inspection of enhanced life-cycle management requirements for these pipelines.

With special permits, PHMSA individually examined the design, construction, and O&M plans for a particular pipeline before allowing operation at a higher pressure than currently authorized. In each case, PHMSA conditioned approval on compliance with a series of rigorous design, construction, O&M, and management standards, including enhanced damage prevention practices. PHMSA's experience with these requests for special permits led to the conclusion that a rule of general applicability is appropriate. With a rule of general applicability, the conditions for approval are established for all without need to craft the conditions based on individual evaluation. Thus, this rule sets rigorous safety standards. In place of individual examination, the rule requires senior executive certification of an operator's adherence to the more rigorous safety standards. An operator seeking to operate at a higher pressure than allowed by current regulation must certify that a pipeline is built according to rigorous design and construction standards and must agree to operate under stringent O&M standards. After PHMSA or 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) receives an operator's certification indicating its intention to operate at a higher operating stress level, PHMSA or the state would then follow up with the operator to verify compliance. As with the special permits, this rule would allow an operator to qualify both new and existing segments of pipeline for operation at the higher MAOP, provided the operator meets the conditions for the pipeline segment.

Several types of pipeline segments will not qualify under this rule. These include the following:

- Pipeline segments in densely populated Class 4 locations. In addition to the increased consequences of failure in a Class 4 location, the level of activity in such a location increases the risk of excavation damage.
- Pipeline segments of grandfathered pipeline already operating at a higher stress level but not constructed in accordance with modern standards. Although grandfathered pipeline has been operated successfully at the higher stress level, PHMSA or the state would examine any further increases individually through the special permit process.
- Bare or ineffectively coated pipe. This pipe lacks the coating needed to prevent corrosion and to make cathodic protection effective.
- Pipelines with wrinkle bends. Section 192.315(a) currently prohibits wrinkle bends in pipeline operating at hoop stress exceeding 30 percent of SMYS.
- Pipelines experiencing failures indicative of a systemic problem, such as seam flaws, during initial hydrostatic testing. Such pipe is more likely to have inherent defects that can grow to failure more rapidly at higher stress levels.
- Pipe manufactured by certain processes, such as low frequency electric welding process.
- Pipeline segments which cannot accommodate internal inspection devices.

We are establishing slightly different requirements for segments that have already been operating and those which are to be newly built. Some variation is necessary or appropriate for an existing pipeline. For example, the requirement for cathodically protecting pipeline within 12 months of construction is an existing requirement for all pipelines. A requirement for the operator of an existing pipeline segment to prove that the segment was in fact cathodically protected within 12 months of construction provides greater confidence in the condition of the existing segment. Allowing proof of five percent fewer nondestructive tests done on an existing segment at the time of construction recognizes the possibility that some welds may not be tested when 100 percent nondestructive testing is not required. The overriding principle in the variation is to allow qualification of a quality pipeline with minimal distinction. Based on our review of requests for special permits on existing pipelines, PHMSA does not believe the more rigorous standards we are requiring are too high for existing segments of modern design and construction. Setting the qualification standards lower for existing pipeline segments could encourage operators to construct a pipeline at the lower standards and seek to raise the operating pressure at some future date.

PHMSA acknowledges this rule may not cover all conditions encountered by a pipeline operator. Further, operators may have innovative alternative methods to the guidelines contained in this rule. To that end, operators may apply to PHMSA or 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) for a special permit requesting to implement the alternative methods.

B.6. How To Handle Special Permits and Requests for Special Permits

A number of pipeline operators have submitted requests for special permits seeking relief from the current design requirements to allow operation at higher stress levels. For the most part, this rule addresses the relief requested. PHMSA has already granted many of these under terms and conditions that may vary slightly from those in this final rule. In some cases, the relief granted is specific to the relief requested by the operator and extends beyond the scope of this rulemaking. PHMSA has continued review of pending special permit applications while working on this rulemaking, in recognition that a final rule may not be issued by the time an operator intended to operate its pipeline at a higher operating stress level. With the publication of this final rule, this case-by-case approach to approving operation under a special permit at higher operating stress levels is no longer needed.

PHMSA will terminate its review of any pending applications for special permits associated with operation at higher operating stress levels once this final rule is issued. Operators of those pipelines must comply with this final rule in order to operate their pipelines at a higher alternative MAOP. PHMSA will examine special permits that have already been granted, as appropriate, to determine if any modifications are needed in light of safety decisions made in preparing this rule.

B.7. Statutory Considerations

Under 49 U.S.C. 60102(a), PHMSA has broad authority to issue safety standards for the design, construction, O&M of gas transmission pipelines. Under 49 U.S.C. 60104(b), PHMSA may not require an operator to modify or replace existing pipelines to meet a new design or construction standard. Although this rule includes design and construction standards, these standards simply add more rigorous, non-mandatory requirements. This rule does not require an operator to modify or replace existing pipelines or to design and construct new pipeline in accordance with these non-mandatory standards. If, however, a new or existing pipeline meets these more rigorous standards, the rule allows an operator to elect to calculate the MAOP for the pipeline based on a higher stress level. This would allow operation at an increased pressure over that otherwise allowed for pipeline built since the Federal regulations were issued in the 1970s. To operate at the higher pressure, the operator would have to comply with more rigorous O&M, and management requirements.

Under 49 U.S.C. 60102(b), a gas pipeline safety standard must be practicable and designed to meet the need for gas pipeline safety and for protection of the environment. PHMSA must consider several factors in issuing a safety standard. These factors include the relevant available pipeline safety and environmental information, the appropriateness of the standard for the type of pipeline, the reasonableness of the standard, and reasonably identifiable or estimated costs and benefits. PHMSA has considered these factors in developing this rule and provides its analysis in the preamble.

PHMSA must also consider any comments received from the public and any comments and recommendations of the TPSSC. These are discussed below.

C. Comments on the NPRM

PHMSA received comments from 19 organizations in response to the NPRM. These included eleven pipeline operators, four trade associations and related organizations, three steel/pipe manufacturers, and one state pipeline safety regulatory agency.

C.1. General Comments

API 5L, 44th Edition

Many commenters noted that pipe material/design requirements in American Pipeline Institute (API) Standard 5L (API 5L) have been significantly revised in the 44th edition, which they stated would be in effect by the time a final rule is issued. These commenters generally suggested that PHMSA should defer to, or incorporate, requirements from the 44th edition where applicable rather than establishing different technical requirements in regulation.

Response

API 5L, 43rd edition, is currently incorporated by reference into the Code of Federal Regulations (CFR). PHMSA has begun a technical review of the 44th edition to determine whether and to what extent it is appropriate to update this reference or if exceptions need be taken when so incorporating the standard. PHMSA cannot reference requirements in the 44th edition until this review is completed and the regulations have been revised to incorporate the new edition. Where differences in the 44th edition would affect requirements in this rule, appropriate changes will be made when that edition is incorporated.

Effect on Special Permits

All commenters who addressed the question suggested that requirements in a final rule should not apply retroactively to pipelines operating at alternative MAOP based on special permits issued after detailed review by PHMSA. One pipeline operator provided a legal analysis maintaining that such retroactive application would be contrary to PHMSA's statutory authority. These organizations also commented that PHMSA should continue review of special permit applications until the final rule is issued, noting that in many cases operation at the proposed higher MAOP is necessary to meet contractual commitments operators have made in anticipation of a special permit being granted and to meet national energy needs.

Response

As noted above, PHMSA continued reviewing special permit applications throughout this rulemaking proceeding, generally applying the same criteria adopted in this rule. Having now published the final rule, we consider it unnecessary to complete review of pending special permit applications on the subject. Accordingly, PHMSA intends to terminate these proceedings, with appropriate notice to the individual applicants.

In contrast, this regulatory action has no effect on the status of special permits or waivers currently in effect. As we explained recently in Docket No. PHMSA–2007–0033, *Pipeline Safety: Administrative Procedures, Address Updates, and Technical Amendments,* (FR Volume 73, No. 61, 16562, published March 28, 2008), PHMSA reserves the right to revoke or modify a special permit or waiver based on an operator's failure to comply with the conditions of the special permit/waiver or on a showing of material error, misrepresentation, or changed circumstances. Although an operator may elect to surrender its special permit at any time, nothing in this rule requires the operator to do so or otherwise triggers reopening of a special permit/waiver currently in effect. The existing MAOP special permits were issued based upon a PHMSA review of the operator's engineering, construction, O&M procedures and operating history. While some of the pipeline segments may not meet all of the requirements specified in this final rule, the operational history and O&M practices provide an equivalent level of safety as provided in this final rule. Furthermore, whether a pipeline is operating at higher MAOP under this rule or a special permit/waiver, PHMSA will monitor and enforce compliance with the applicable conditions and safety controls.

Structure

One state pipeline safety regulatory agency expressed concern about the complexity and inconsistency being added to the regulations as a result of the structure of the proposed rule. The state agency noted that the proposal would add many pages to part 192 that would apply to only a limited number of gas transmission operators. The agency suggested that it would be more effective, and cause less confusion, if requirements for pipelines operating at an alternative MAOP were presented in a separate subpart, applicable only to those pipelines.

Response

PHMSA has not previously used a separate subpart to include varied requirements applicable to specific types of pipelines. Instead, subparts have been used for individual topics, such as Corrosion Control or Integrity Management. PHMSA considers it more appropriate to incorporate requirements applicable to each subpart as the requirements in this rule implicate several subparts. PHMSA also notes that no other commenters indicated that the structure of the proposed rule was confusing. PHMSA has retained the structure of the proposal in this final rule. PHMSA intends to post this notice of final rulemaking on its web site, which will provide a reference for pipeline operators that includes all of the requirements associated with alternative MAOP in one document.

C.2. Comments on Specific Provisions in the Proposed Rule

C.2.1. Section 192.7, Incorporation by Reference

Interstate Natural Gas Association of America (INGAA) and three pipeline operators supported incorporation of American Society of Testing and Materials (ASTM) standard ASTM A–578/A578M–96 into the regulations. These commenters generally noted that this action is consistent with reliance on consensus standards, which they support. American Gas Association (AGA) and the Gas Piping Technology Committee (GPTC) took the contrary position and opposed incorporation of the ASTM standard. GPTC commented that the standard is used by one mill and that other mills use other standards (including International Standards Organization (ISO) standards). GPTC also noted that there are a number of equivalent standards and that PHMSA should not select one for incorporation. AGA added that incorporating the standard could have unintended consequences of making the rule too prescriptive and precluding the use of equivalent standards.

Response

The final rule incorporates ASTM A578/A578M–96 into the regulations. Incorporation by reference makes the provisions of the standard apply, when it is referenced in a regulation, in the same manner as if they were written in the CFR. Referencing consensus standards wherever possible is the policy of the Federal government.

This standard is referenced in the regulation for assuring plate/coil quality control (QC). That reference requires that ultrasonic (UT) testing be conducted in accordance with the standard, API 5L paragraph 7.8.10, or equivalent. The pipe must also be manufactured in accordance with API 5L which is already referenced in § 192.7. PHMSA considers that the allowance for use of an equivalent standard renders moot the concerns expressed by AGA and GPTC.

C.2.2. Design Requirements

Section 192.112(a), General Standards for the Steel Pipe

Carbon equivalent: INGAA, five pipeline operators and two pipe manufacturers all noted that the proposed limit in paragraph (a)(1) on carbon equivalent (CE) (0.23 percent Pcm) is inconsistent with the 44th edition of API 5L. INGAA and one operator suggested deleting the limit from the proposed rule. Two operators noted that the NPRM described no analysis or data showing the need for a different limit. Several commenters indicated that high-strength pipe (grades X–80 and above) is difficult to achieve with the stated limit. One operator suggested that weldability is the key issue and that allowance for a higher CE is particularly important for high-strength and strain-based pipe. A steel manufacturer objected to sole reliance on the Pcm formula for determining the CE value.

Response

PHMSA agrees that the limit in API 5L is acceptable. PHMSA has changed the limit for CE to 0.25 Pcm (Ito-Bessyo formula for CE), which is consistent with API 5L. PHMSA does not agree that no limit should be included in the CFR. PHMSA considers that a limit is necessary to assure the quality of steel used for pipelines to operate at an alternative MAOP. Weldability tests are not timely for determining the acceptability of steel, as they cannot be performed until pipe is manufactured. Recent experience with several new pipelines using X–80 steel has indicated that such high strength steel can meet the CE limit. PHMSA does not currently have experience with steels of grades higher than X–80 and will need to understand what is important for such pipe grades as they are used.

PHMSA acknowledges that there are other methods for calculating the CE value of steel. The Pcm formula included in the proposed rule is a method used by several mills. PHMSA has revised the final rule to include use of an alternate International Institute of Welding (IIW) CE formula, used by other mills for determining CE.

Diameter to thickness ratio: INGAA and three pipeline operators suggested deleting the limit in proposed paragraph (a)(3) on the ratio of pipe diameter to thickness (D/t). They maintained that this limit may be inappropriate for high-grade pipe and that the concerns that might underlie such a limit are adequately addressed by the proposed rule and common construction practices and quality assurance (QA). One operator noted that ovality and denting issues are addressed by the proposed construction requirements of § 192.328, that QA is required by proposed § 192.620(d)(9), and that the baseline geometry ILI and the provisions of the ASME Code would also address the underlying concerns.

Response

PHMSA has retained the proposed limit. PHMSA adopted this limit (*i.e.*, $D/t \leq 100$) based upon presentations made by industry experts at the public meeting on ''Reconsideration of Maximum Allowable Operating Pressure in Natural Gas Pipelines'' held on March 21, 2006 in Reston, VA. Higher D/t ratios can lead to excessive denting during transportation, construction bending, pipe stringing on the right-of-way, backfilling, and hydrostatic testing.

Section 192.112(b), Fracture Control

Several commenters noted that some requirements included in the proposed rule are being eliminated or significantly revised in the 44th edition of API 5L. The steel/pipe manufacturers suggested referencing the new standard to, among other things, avoid unnecessarily limiting approaches to deriving arrest toughness and treating all sizes and types of pipe (*e.g.*, seamless) the same for purposes of the drop weight test.

INGAA and three pipeline operators suggested a change to allow a crack arrest design other than mechanical arrestors if crack propagation cannot be made self-limiting. (One operator noted that Clock Spring [1] is marketed as a crack arrestor). They suggested that a rule should allow an option for engineering analysis, including an analysis of consequences. One operator noted that this option could be particularly important for high-pressure, large-diameter pipelines. Two operators generally supported the proposed approach for fracture control if self-arrest is attainable. They noted that it is critical that operators have a plan and consider the potential under-

[1] Clock Spring is a commercially available composite sleeve used for pipeline repairs.

conservativeness of Charpy toughness equations for high grade pipe (X–70 and above).

Response

PHMSA has not yet incorporated the 44th edition of API 5L into the regulations. PHMSA is conducting a technical review of this edition to determine if it is acceptable for incorporation. If, after that review, PHMSA determines that the standard is acceptable, PHMSA will propose to incorporate the 44th edition and change other affected rules as appropriate.

The final rule requires an overall fracture control plan to resist crack initiation and propagation and to arrest a fracture within eight pipe joints with a 99 percent occurrence probability and within five pipe joints with a 90 percent occurrence probability. Research has shown that an effective fracture plan should include acceptable Charpy impact and drop weight tear tests, which are required in this final rule.

PHMSA considers composite sleeves to be suitable mechanical crack arrestors. Operators could use composite sleeves for this purpose, install periodic joints of thicker-walled pipe, or use other design features to provide crack arrest if it is not possible to achieve the toughness properties specified in the rule and also assure self-limiting arrest. PHMSA has revised the language in this final rule to allow additional design features and to make mechanical crack arrestors an example of such features rather than the only method allowed.

Section 192.112(c), Plate/Coil Quality Control

One pipeline operator and two pipe manufacturers suggested expanding the mill control inspection program to a full internal quality management program and including caster and plate/coil/pipe mills.

INGAA, three pipeline operators and two pipe manufacturers commented that the specificity of requirements applicable to mill inspection should be reduced. These commenters agreed that a macro etch test is appropriate but suggested that the details of how this test is applied should be left to decisions of the mill and the pipe purchaser. They suggested that API 5L provides a foundation for those decisions and the specific requirements in the proposed rule add unnecessary cost impact. One pipe manufacturer noted that the Mannesmann scale is very subjective, while a second separately commented that reference to the Mannesmann scale should be deleted because it is proprietary and thus inappropriate for inclusion in a regulation. One operator requested that the mill inspection requirements, including those for macro etch and UT examination, be explicitly limited to new pipelines, noting that it is unlikely these tests were performed for any existing pipelines and that they have minimal relevance for existing pipelines that would be subject to the proposed rule.

INGAA and four pipeline operators suggested that an alternative to the UT testing specified should be allowed for identifying laminations. They suggested that a full-body UT inspection, for example, should be acceptable.

One operator and two manufacturers commented that it is inappropriate to use the proposed macro etch test and acceptance criteria as a heat/slab rejection criteria. These commenters noted that no consensus standard references this test. The operator maintained that the test does not accomplish what PHMSA suggested in the preamble of the NPRM, that it is a lagging rather than a leading test and its use as an acceptance test without a retest allowance could result in rejection of up to 2,000 tons of steel or more. The operator suggested that this should be a mill control test rather than an acceptance test with specifics, including retest allowance, to be negotiated between the mill and pipe purchaser.

One operator and one manufacturer noted that ASTM A578 is a plate UT inspection standard. They commented that specifying this standard for coil/pipe is beyond its scope. They also commented that we gave no basis for proposing that 50 percent of surface and 90 percent of joints be examined. They noted that pipe seam welds and pipe ends are inspected radiographically or by UT and that additional UT is more appropriately a purchaser-specified requirement. Another operator also suggested that the 50 percent surface coverage requirement be deleted in favor of reference to ASTM A578/A578M.

Two manufacturers suggested that the rule allow UT on plate/coil or pipe body, noting that most United States mills lack equipment to perform ASTM A578 testing. Another manufacturer suggested that a combination of electromagnetic inspection (EMI) and UT inspection is superior and would produce the most dramatic impact. This combination, according to this manufacturer, is also applicable to seamless and electric resistance welded (ERW) pipe.

One manufacturer recommended that the inspection program of proposed section 192.112(c)(2)(ii) be limited to submerged arc welded (SAW) pipe, and that the acceptance criteria for UT testing be referenced to ASTM A578 or equivalent. This commenter noted that laminations are not a significant issue for modern pipe.

Response

PHMSA agrees that an ‘‘internal quality management program’’ is more descriptive than a ‘‘mill control inspection program’’ and that such a program should be required at all mills associated with the manufacture of steel and pipe. The final rule has been revised accordingly.

PHMSA considers that a macro etch test or other equivalent method is needed to identify inclusions that may cause centerline segregation during the continuous casting process. The acceptance criteria must be agreed to between the purchaser and the mill. PHMSA has added an alternative to the requirement for a macro etch test consisting of an operator QA monitoring plan that includes audits conducted by the operator (or an agent operating under its authority) of: (a) Steelmaking and casting facilities; (b) QC plans and manufacturing procedure specifications (MPS); (c) equipment maintenance and records of conformance; (d) applicable casting superheat and speeds; and (e) centerline segregation monitoring records to ensure mitigation of centerline segregation during the continuous casting process.

PHMSA agrees that alternate methods to test the pipe body for laminations, cracks, and inclusions should be acceptable and has revised the rule to allow methods per API 5L Section 7.8.10 or ASTM A578-Level B, or other equivalent methods. PHMSA understands that it is unlikely that many existing pipelines were manufactured using processes that included the specified examinations but does not consider that sufficient reason for excluding existing pipelines from the requirements.

The requirement for 50 percent of surface and 95 percent of lengths of pipe to be UT tested was set to ensure adequate QC standards. PHMSA agrees that the specified QC requirements also must be practical. In the final rule, we have reduced the requirement for 50 percent of surface coverage to 35 percent because we recognize that it may be difficult to achieve 50 percent coverage for pipe manufactured with helical seams.

PHMSA has not deleted reference to the Mannesmann scale, which is widely used by steel manufacturers. In addition, the regulation allows for use of equivalent measures.

PHMSA does not agree that the inspection program of proposed 192.112(c)(2)(ii) should be limited to SAW pipe. PHMSA considers this requirement to be an overall quality management tool and not just for laminations. Additionally, PHMSA notes that at least one recently constructed pipeline has had problems with laminations.

Section 192.112(d), Seam Quality Control

INGAA, four pipeline operators, and two pipe manufacturers all recommended additional reliance on the procedures of API 5L 44th edition. The manufacturers would have referenced API 5L for toughness requirements and made them applicable to weld and heat affected zone in SAW pipe only. They noted that the proposed requirement is inappropriate for ERW pipe, that the specified toughness is higher than that called for in API 5L and is not necessary. The manufacturers believe that fracture arrest capabilities are not needed in weld metal, since staggered seams in pipeline construction result in arrest occurring in the pipe body.

INGAA and three pipeline operators would have eliminated reference to specific hardness testing or a maximum hardness level, arguing that API 5L contains sufficient guidance. They further noted that the specified hardness of 280 Vickers (Hv10) is only for sour gas. One manufacturer would have relaxed the hardness requirement to 300 Hv10 and allowed for equivalent test methods (per ASTM E140). Another would have specified a maximum hardness ''appropriate for the pipeline design'' vs. specifying a limit. The first manufacturer noted that API 5L does not specify hardness limits except for sour gas service or offshore pipelines and that the technical justification for these limits on other pipe is not obvious. The manufacturers maintained that limiting hardness may not allow attaining the best weld properties and that 280 Hv10 is likely not attainable for pipe grades X–80 and above.

Two pipe manufacturers requested that the rule be clarified to indicate that the seam QC requirements apply only to longitudinal or helical seams. They noted that pipe mill jointer welds require radiography per API 1104 and that significant capital expense would be required for pipe mills to UT test jointer and skelp end welds after cold expansion and hydrostatic testing.

Response

PHMSA has not yet incorporated the 44th edition of API 5L into the regulations. PHMSA is conducting a technical review of this edition to determine if it is acceptable for incorporation. If, after review, PHMSA determines that the standard is acceptable, PHMSA will propose to incorporate the 44th edition and propose changes to other affected regulations as appropriate.

PHMSA has deleted the proposed limit on toughness. This limit was not included in the conditions applied to special permits issued for alternative MAOP operation. Pipe procured to modern standards generally meets the proposed limit, and other requirements in this rule, provide for crack arrest. Thus, PHMSA concluded that a toughness limit was not needed.

PHMSA does not agree that it is not necessary to specify a hardness limit. All recent pipelines for which special permits have been issued to operate at alternative MAOP have met the proposed hardness limit without apparent difficulty. This includes X–80 pipe. The requirement helps assure that only high-quality steel is used for pipelines to be operated at alternative MAOP. Hardness must be limited to assure welds are not susceptible to cracking. The proposed limit has been retained in the final rule.

PHMSA intends the proposed seam inspection requirements to apply to pipe seam welds and not to jointer or skelp welds. The title of this subparagraph is ''Seam quality control,'' and its requirements all refer to ''seam welds'' or ''seams.'' PHMSA does not consider that additional changes are needed to clarify the applicability of these requirements.

Section 192.112(e), Mill Hydrostatic Test

Most commenters objected to the proposed requirement that mill hydrostatic tests be held for 20 seconds. They noted that mills typically follow API 5L, which specifies a hydrostatic test of 10 seconds and that changing this standard could reduce mill productivity. One operator also noted that a more rigorous qualification test is already specified elsewhere in the proposed regulation.

One manufacturer would have limited the required maximum test pressure to 3,000 psi if there are physical limitations in mill test equipment that preclude obtaining higher pressures. The manufacturer stated that most mills cannot achieve test pressures above 3,000 psi, which is the maximum specified in API 5L and that upgrades to equipment would cost from $0.5 to $4 million per tester.

Response

PHMSA agrees that a 20-second mill hydrostatic test is not needed and has revised the final rule to reduce the required hold time to 10 seconds. While a longer mill hydrostatic test may allow the discovery of more pipe defects, the benefit is marginal. The pipeline will later be subject to a much longer hydrostatic test prior to being placed in service according to 192.505(c). Moreover, in the case of Class 1 and 2 locations, the pipe will be tested at a higher stress level than the mill hydrostatic test according to 192.620(a)(2).

PHMSA does not consider it appropriate to limit the maximum test pressure to reflect the reported mill limitations. In practice, the need for tests above 3,000 psi should be rare. Test pressures that high would only be required for pipeline in a Class 3 location operating at a very high MAOP.

Section 192.112(f), Coating

INGAA, GPTC, and eight pipeline operators all objected to the proposed requirements that would have limited operation at an alternative MAOP to pipe coated with fusion bonded epoxy (FBE). The commenters noted that specifying any single coating type would stifle innovation. They suggested that a performance-based requirement would be more appropriate. The important performance characteristics they identified include non-disbonding and non-cracking. Two operators would add non-shielding, and GPTC suggested specifying that coating must meet or exceed the protection of FBE.

GPTC and one operator requested clarification that girth welds can be coated with other than FBE. GPTC also requested clarification that the proposed requirement in subparagraph 2 that coatings used for trenchless installation must resist abrasion and other damage applies to the coatings described under subparagraph 1.

Response

PHMSA agrees that specifying a particular coating could stifle innovation and we have revised the final rule to require non-shielding coatings. Eliminating reference to FBE coating in this section obviates the need for additional changes to note that girth welds can be coated with other than FBE.

PHMSA has made a minor change in response to GPTC's request for clarification. Subparagraph 192.112(f)(2) now requires that coatings used for trenchless installation must resist abrasions and other installation damage ''in addition to being non-shielding.''

Section 192.112(g), Flanges and Fittings

INGAA and three pipeline operators generally supported the proposed requirements for certification records and a pre-heat procedure for welding of components with CE greater than 0.42 percent, but maintained that existing standards and operator supplemental requirements are adequate to assure the integrity of flanges and fittings. The operators cited specific standards to which fittings and flanges should be purchased. Another operator noted that the proposed requirements go beyond API and ASTM standards, and suggested that the new requirements should be part of an industry standard. This operator also suggested that PHMSA establish a minimum size below which certifications would not be required.

GPTC requested clarification as to what certification is required and what requirements/specifications are to be certified.

Response

PHMSA has concluded that no changes are needed to the standards proposed for flanges and fittings. It is likely that flanges and fittings procured to current standards will meet the rule's requirements. PHMSA will review the degree of compliance during inspections of pipelines being constructed or upgraded for operation at an alternative MAOP. PHMSA does not agree that the proposed requirements go beyond API and ASTM standards. Fittings, flanges and valves manufactured to API, ASTM, and/or ASME/ANSI standards should not be operated above the maximum operating pressure limits of those industry standards for the product rating. This rule change is not intended to increase maximum operating pressure limits or designated pressure or temperature rating of referenced code standards.

In the final rule, PHMSA has clarified that certification must address chemistry, strength and wall thickness.

Section 192.112(h), Compressor Stations

Commenters expressed concern about the proposed requirement to limit compressor station discharge temperatures to 120 degrees Fahrenheit (49 degrees Celsius) unless testing shows the coating can withstand higher temperatures in long-term operations. INGAA and four pipeline operators would allow ''research'' in addition to testing to permit operation above 120 degrees Fahrenheit. INGAA submitted a white paper titled ''A Review of the Performance of Fusion-Bonded Epoxy Coatings on Pipelines at Operating Temperatures Above 120 °F'', dated May 16, 2008, describing research it believes is relevant. The commenters stated that more testing is not needed, because FBE coating has been shown effective by research and experience in service. They maintained that disbonding may occur but is irrelevant because FBE coating is conductive and cathodic protection is still effective.

One pipeline operator would have allowed operation at a higher compressor station discharge temperature if justified by test or data held by the manufacturer, coating applicator, or operator. The operator maintained that modern coating can withstand higher temperatures, and that maintaining 120 degrees Fahrenheit may be impractical on hot days (during which peak loads often occur) in southern locations. Another operator suggested allowing operators to rely on FBE manufacturers' specifications as the ''testing'' adequate to allow operation above 120 degrees Fahrenheit, limiting operation to 90 percent of the manufacturer's continuous operating temperature. Another operator suggested allowing a long-term coating integrity monitoring program as an alternative to designing compressor stations to limit discharge temperature to 120 degrees Fahrenheit.

A state pipeline safety regulatory agency suggested that alternative approaches be allowed. The agency suggested that operators could install heavier walled pipe and operate at conventional MAOP for the distance required to assure that pipe wall temperatures would be below 120 degrees Fahrenheit. This commenter stated its belief that this would be a simpler and cheaper solution to the concern over compressor station outlet temperature and that its use should not be precluded.

Response

PHMSA is not persuaded by the arguments put forth by commenters, and in the INGAA white paper titled ''A Review of the Performance of Fusion-Bonded Epoxy Coatings on Pipelines at Operating Temperatures Above 120 °F'', dated May 16, 2008, that operation above 120 degrees Fahrenheit is simply acceptable. In fact, the INGAA white paper confirms that disbonding and possibly cracking of FBE coating is more likely to occur at operating temperatures above 120 degrees Fahrenheit. PHMSA disagrees that disbonding is irrelevant because disbonded FBE remains conductive and an operating cathodic protection system will protect the pipeline from corrosion.

External corrosion is one of the most significant threats affecting steel pipelines. PHMSA regulations require two levels of protection against this threat: Coating and cathodic protection. These requirements are intended to provide redundant protection. If coating fails, cathodic protection continues to protect the pipe. If cathodic protection fails, the coating is still present. PHMSA agrees that it is important that disbonded coating remain conductive to assure continued protection by cathodic protection. This is why the rule has been revised to require ''non-shielding'' coating. At the same time, PHMSA does not consider it acceptable to ignore known circumstances in which one of the protections against corrosion is likely to fail simply because the other exists. If PHMSA believed only one level of protection were needed, the regulations would require either coating or cathodic protection. INGAA's white paper confirms that there is a significant likelihood that one of the levels of protection against corrosion (*i.e.*, coating) will fail if operated above 120 degrees Fahrenheit. For pipelines to be operated at an alternative MAOP, where the margin for corrosion is smaller than for pipelines conforming to the existing regulations, PHMSA will not accept this higher likelihood of failure of the coating system.

Nevertheless, PHMSA recognizes that improvements in coating systems may allow operation above 120 degrees Fahrenheit without significantly higher likelihood of disbonding. Thus, the rule allows operation above this temperature if research, testing, and field monitoring tests demonstrate that the coating type being used will withstand long-term operation at the higher temperature. The operator must assemble and maintain the data supporting higher-temperature operation. Research, testing and field monitoring must be for coating by the same manufacturer and must be specific to the brand of coating (if the manufacturer makes more than one brand), application temperature, or operating temperature rated coating.

PHMSA agrees that a long-term coating integrity monitoring program can also assure that coating remains effective at higher operating temperatures, but the effectiveness of such a program depends on how it is structured and implemented. PHMSA would expect, for example, that a monitoring program being used as a basis for operating at temperatures above 120 degrees Fahrenheit would include periodic examinations to assure coating integrity (*e.g.*, direct current voltage gradient). PHMSA has modified the final rule to allow a long-term coating integrity monitoring program to be used as a basis for allowing pipe temperatures in excess of 120 degrees Fahrenheit, but operators must submit their programs to the PHMSA pipeline safety regional office in which the pipeline is located for review before pipeline segments may be operated at alternative MAOP at these higher temperatures. PHMSA's review will help assure that the monitoring programs are comprehensive enough to assure long-term coating integrity, to identify instances in which coating integrity becomes degraded, and to address those problems. 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.

Where compressor station compression ratios raise the temperature of the flowing gas to above 120 degrees Fahrenheit, operators should consider installing gas coolers at compressor stations. This practice has been successfully used in the industry to cool the gas stream to not damage the pipe external coating.

PHMSA agrees that the alternative of heavier walled pipe operated at conventional MAOP for the distance required to assure that pipe wall temperatures do not exceed 120 degrees Fahrenheit suggested by the state regulator is also an acceptable method of addressing the concern of high-temperature operation. PHMSA has made minor changes to the rule to make it clear that this option is not precluded.

C.2.3. Construction Requirements

Section 192.328(a), Quality Assurance (QA)

Four pipeline operators supported the QA requirements of proposed § 192.328(a). A state pipeline safety regulator noted that subparagraph 2(ii) duplicated requirements in proposed § 192.620(c)(5) and questioned why both sub-rules were needed.

Response

PHMSA's experience in regulating pipelines operating at higher MAOPs under special permits has indicated that control of quality is subject to frequent problems. As a result, PHMSA considers that an explicit requirement for a QA plan during construction is needed. The requirements of proposed § 192.620(c)(5) also addressed quality concerns, but they relate principally to personnel qualification. As described below, this proposed paragraph has been revised in the final rule to more explicitly address the qualification of personnel performing construction tasks.

Section 192.328(b), Girth Welds

INGAA and four pipeline operators suggested moving the requirement for testing of girth welds on existing pipelines from § 192.328 to § 192.620. They believe that the requirement is inappropriately located in a construction section that is not otherwise applicable to existing pipe.

Response

PHMSA agrees and has moved this requirement in the final rule to § 192.620(b) as one of the criteria for determining when an existing pipeline can be operated at alternative MAOP.

Section 192.328(c), Depth of Cover

Three pipeline operators supported the proposed depth of cover requirements, although one would clarify that they apply to new construction. Another operator suggested that allowance be made for less depth of cover if alternative means of protection are used (*e.g.*, concrete slabs) that offer equivalent protection.

Response

PHMSA agrees that alternative protection is acceptable and has revised its proposed rule accordingly in this final rule. To satisfy the rule, alternative protection must provide equivalent protection and the operator must demonstrate this equivalence. Simply providing barriers without demonstrating that they provide equivalent protection is not sufficient.

PHMSA did not intend this requirement to apply to new construction only and thus, has not changed the requirement in the final rule. PHMSA considers that a pipeline to be operated at alternative MAOP, including existing pipelines, must have superior protection from outside force damage. PHMSA recognizes that existing pipelines constructed in compliance with § 192.327 may have less cover than required in this rule. Operators of those pipelines desiring to implement alternative MAOP must provide equivalent protection for those segments not meeting the depth of cover requirements.

Section 192.328(d), Initial Strength Testing

A number of commenters objected to the proposed requirement that any failure indicative of a fault in material disqualifies a pipeline segment from operation at an alternative MAOP. The commenters suggested that a root cause analysis be permitted, consistent with previously-issued special permits, to determine if the fault indicates a systemic issue. Disqualification is only appropriate, according to the commenters, if a systemic issue exists, and failures can result from isolated causes. One operator would also clarify that these requirements apply to base pipe material rather than flanges, gaskets, etc. Another suggested that multiple test failures can actually be beneficial, because they prompt additional failure analyses that better assure the integrity of the non-failed pipe.

Response

PHMSA agrees that a single failure can reflect an isolated cause and should not disqualify an entire segment from operation at an alternative MAOP if it can be demonstrated that the failure is not indicative of a problem that could affect the rest of the pipeline segment. PHMSA has revised the final rule to allow a root cause analysis of any failures as a way of justifying qualification of a pipeline segment. Root cause analysis must demonstrate that failures in alternative MAOP pipeline segments are not systemic. Operators are required to notify PHMSA of the results of their evaluations, which will allow us to validate their conclusions.

Section 192.328(e), Cathodic Protection

INGAA and seven pipeline operators suggested that this paragraph be deleted, since it duplicates requirements in § 192.455. One of the operators further commented that whether cathodic protection was operational within 12 months becomes irrelevant once the line is assessed and its condition is known.

Response

PHMSA recognizes that § 192.455 requires that cathodic protection be operational within 12 months of placing a pipeline in service but does not consider the requirement in this rule duplicative. Operators who complied with § 192.455 will, of course, meet this criterion for operation at alternative MAOP. Those who did not install cathodic protection within 12 months of initial operation will not, whether or not § 192.455 was effective at the time. PHMSA considers it critical that cathodic protection be provided as quickly as possible after construction, because there are some forms of corrosion that can result in high corrosion rates (*e.g.*, microbiological corrosion and corrosion from current faults) producing significant loss of pipe wall in a short period of time. Operation at alternative MAOP is thus not allowed for those pipelines for which cathodic protection was not provided within 12 months of initial operation.

PHMSA has moved this requirement from § 192.328, a section addressing construction requirements, to § 192.620(d)(8), a section addressing operations and maintenance requirements. PHMSA believes that this change will help emphasize that this is not simply a re-statement of the requirement in § 192.455.

Section 192.328(f), Interference Currents

Three pipeline operators supported the proposed requirements in this subparagraph (one with the understanding that § 192.473 will govern for an existing Class 1 pipeline). Taking a contrary position, another operator urges PHMSA to delete this paragraph because the requirement is already addressed in the regulations and it is difficult to address all interference issues during construction without active cathodic protection (cathodic protection is not required to be in service until 12 months after construction).

Response

It is important to address the potential for interference currents as early as possible. Some pipelines have experienced significant wall loss in the first months of operation due to the effect of interference currents. While it may be true that all interference currents cannot be identified before cathodic protection is in operation, many can be anticipated and remediated during construction. These include the effects of electric transmission lines or electrified trains sharing or paralleling a right of way, or other ground beds in proximity to the pipeline's route. Operators need to address, during construction, interference currents that can be anticipated. Review of cathodic protection effectiveness once it is in operation may identify additional issues, and operators need to deal effectively with these. It is not necessary, however, and potentially deleterious to pipeline integrity to delay all actions addressing interference currents until this time. The provisions proposed in the NPRM remain unchanged in the final rule.

C.2.4. Eligibility for and Implementing Alternative MAOP

Section 192.620(a), Calculating an Alternative MAOP

Most commenters from the pipeline industry objected that the proposed requirements for calculating an alternative MAOP did not recognize that class locations may change once a pipeline is in service. They noted that § 192.611 recognizes this for conventional MAOP pipelines, and allows operation following a class change at a higher MAOP than would be required for new pipe in that class provided that testing was performed at a sufficiently high pressure. The commenters sought similar treatment for alternative MAOPs in this paragraph and conforming changes to the language in § 192.611 concerning class location changes. These commenters also noted that the proposed rule does not explicitly address compressor stations, meter stations, etc.

Two pipeline operators would reduce the test factor for Class 2 locations from 1.5 to 1.25. They contended that this would allow testing of Class 1 and 2 pipelines to be done together, thereby minimizing environmental disruption that would be associated with separately testing Class 2 to a higher factor. They noted that testing of both classes together would not be possible with a specified test factor of 1.5 for Class 2, since this would overstress the Class 1 pipe (*i.e.*, exceed 100 percent SMYS).

One operator suggested allowing a test factor of 1.25 for existing pipelines and requiring 1.5 only for lines installed after the effective date of this rule. They contended that specifying 1.5 as a design factor for Class 2 results in the alternative MAOP for Class 2 pipe segments being less than currently allowed for existing pipelines.

Two operators suggested that PHMSA amend the proposed rule to explicitly state that the design factors will increase for facilities (stations, crossings, fabricated assemblies, etc.) upgraded in accordance with the rule. One suggested stating that an increase of approximately 11 percent is allowed. The other suggested specific design factors of 0.56 for station pipe, 0.67 for fabricated assemblies and uncased road/railroad crossings in Class 1 areas, and 0.56 for such assemblies/crossings in Class 2 locations.

The state pipeline safety regulatory agency commented that the rule should contain only one provision regarding the test pressure used in determining the MAOP. This commenter noted proposed § 192.620(a)(2)(ii) limits MAOP to 1.5 times the test pressure in Class 2 and 3 locations and that proposed § 192.620(c)(3) allows 1.25 times test pressure in all classes. The commenter contends that a reference in the latter requirement to the former creates a confusing circularity.

Response

PHMSA agrees that the proposed regulation could be more restrictive than existing requirements in § 192.611 in the event of a class change. As noted in the comments, the existing regulation allows operation at a higher MAOP following a class change (*i.e.*, higher than would be required for a new pipeline installed in that class location) provided that testing has been conducted at a sufficiently high pressure to demonstrate adequate safety. PHMSA has revised the final rule to be more consistent with § 192.611 in allowing operation at a higher pressure following a class change.

PHMSA has reduced the required test pressure for existing pipelines (*i.e.*, pipelines installed prior to the effective date of the rule) in Class 2 locations to 1.25 times MAOP. This is consistent with § 192.611(a)(1). However, if Class 2 pipeline is tested at 1.25 times MAOP, then operation at an increased alternative MAOP following a class change is not allowed. Such testing does not provide sufficient assurance of safety margin for the higher population Class 3 areas. Operators who desire to operate at higher pressures following a change from Class 2 to Class 3 must test their pipe at 1.5 times alternative MAOP.

PHMSA has included alternate design factors for existing facilities and fabricated assemblies to be operated at alternative MAOP. PHMSA does not agree that design factors for facilities and fabricated assemblies are needed for new installations (*i.e.*, those constructed after the effective date of this final rule). PHMSA expects design factors for new facilities (stations, crossings, fabricated assemblies, etc.) to be in accordance with § 192.111(b), (c), and (d).

Section 192.620(b), When may an alternative MAOP be used?

Proposed paragraph b(6) limited eligibility for an alternative MAOP for pipeline segments that have previously been operated to those that have not experienced any failure during normal operations indicative of a fault in material. A number of commenters objected to this limitation, which is similar to the limitation in proposed § 192.328(d) described above. Here, again, the commenters indicated that root cause analysis should be allowed and operation at an alternative MAOP should be proscribed only if the evaluation reveals a systemic issue.

GPTC requested that paragraph b(3) be clarified. That paragraph requires that segments to be operated at alternative MAOP must have remote monitoring and control provided by a supervisory control and data acquisition system. GPTC requested that PHMSA clarify the degree of ''control'' that is required and questioned whether remote control of flow and pressure are required or if remote control of valves is all that was intended.

One pipeline operator requested that either this paragraph or existing § 192.611 be revised to clarify the applicability of the current 72/60/50 percent SMYS limitation on hoop stress. The operator believes it is unclear when and if the § 192.611 limitations on hoop stress apply if an alternative MAOP is used.

Response

PHMSA agrees that exclusion from operation at an alternative MAOP is appropriate only if a failure during mill hydrostatic testing, construction hydrostatic testing, or operation is indicative of a systematic issue. PHMSA has revised the final rule here (in this paragraph and in § 192.328(d) above) to allow root cause analysis with operators required to notify PHMSA of the results.

Control requires that operators monitor pressures and flows as well as compressor start-up and shut-down. Valves must also be able to be remotely closed. The final rule has been modified to make these requirements clear.

PHMSA has revised § 192.611 to include hoop stress limits applicable to pipeline operating at alternative MAOP.

Section 192.620(c), What must an operator do to use an alternative MAOP?

INGAA and four pipeline operators suggested that an engineering analysis should be allowed for existing pipe that was not tested to 125 percent of the alternative MAOP. They noted that some existing pipe may have been tested to higher pressures but not quite to 125 percent, and that this pipe should not be automatically excluded. They noted that experience shows that the vast majority of existing pipe is tested successfully without systemic problems, and that the allowance for 95 percent vs. 100 percent of girth weld examinations in proposed § 192.328(b)(2) establishes a precedent for allowing existing pipe that can not fully meet new pipe criteria to operate at an alternative MAOP.

One pipeline operator suggested that the rule either state that pressure test must be at 125 percent of alternative MAOP for Classes 1, 2, and 3 or be revised to refer to the factors in § 192.620(a)(2)(ii). They contended the proposed language was unclear as to whether 125 percent is sufficient in all class locations.

A state pipeline safety regulatory agency again suggested that the rule should contain only one provision regarding test pressure (see discussion under § 192.620(a) above).

Several commenters addressed training and qualification requirements in proposed § 192.620(c)(5). The state agency noted that they duplicated proposed § 192.328(a)(2)(ii) and essentially applied operator qualification (OQ) requirements (subpart N) to construction personnel. The state agency suggested it would be simpler and less confusing if it were done in subpart N. One pipeline operator also suggested deleting paragraph c(5) and referring to subpart N. This operator noted that the proposed rule used undefined and vague language—terms such as QC and integrity verification (which could be confused with assessments under subpart O). The operator further noted that subpart N requires OQ and that the meaning of its requirements is well known.

GPTC requested clarification that the requirements are only applicable to segments that operate at an alternative MAOP and as to the meaning of the term ''integrity verification method.''

Response

PHMSA does not agree that an engineering analysis provides an adequate basis to justify operation at alternative MAOP. Operators who desire to use an alternative MAOP for existing pipelines that were not tested to sufficient pressures should re-test their pipelines.

PHMSA has revised the final rule to refer to paragraph (a) for test pressures rather than duplicating them. PHMSA agrees that this change could help avoid confusion.

PHMSA agrees that applying the known requirements of subpart N, related to the qualification of personnel performing work on the pipeline, would likely cause less confusion than specifying the alternative, but similar, requirements included in the proposed rule. Pipeline operators are familiar with subpart N, and their training programs under that subpart have been subjected to audits by PHMSA or states, as appropriate. By its terms, though, subpart N does not apply to construction tasks, since they are not ''an operations or maintenance task''—one part of the four-part test in § 192.801(b). PHMSA has revised this final rule to provide that ''construction'' tasks associated with implementing alternative MAOP be treated as covered tasks notwithstanding the definition in § 192.801(b). For those tasks, then, the requirements of subpart N will apply. This change obviates the concerns expressed by GPTC and the state agency. (PHMSA disagrees with the state comment, however, that the requirement as proposed duplicated § 192.328(a)(2)(ii), as the latter requirement applied only to girth weld coating and not to all construction-related tasks.)

C.2.5. Operation and Maintenance Requirements

Section 192.620(d), Additional O & M Requirements

Two pipeline operators and one state pipeline regulatory agency suggested that covered pipelines should be held to the same requirements as pipelines in HCA under subpart O. They believe that this would make most of § 192.620(d) unnecessary and would increase flexibility for operators.

The state regulator noted that it would avoid confusion that might be created for covered pipelines that would be subject to both sets of requirements. One operator commented that no technical basis is provided for the proposed requirements, while subpart O is based on science and research.

Response

PHMSA disagrees with these comments and has not changed the final rule because some provisions are more restrictive than subpart O.

Section 192.620(d)(1), Identifying Threats

INGAA and three pipeline operators suggested eliminating the requirement for a threat matrix and the implied need for additional preventive and mitigative measures. They noted that operation at incrementally higher pressures does not inherently increase risk or introduce new threats and that the proposed rule already includes requirements sufficient to address the incremental change.

Response

PHMSA does not agree that the rule necessarily addresses all threats to a pipeline. The rule addresses many known threats; however, other threats may exist or develop that may affect the pipeline's integrity. It is up to the operator to identify and evaluate possible pipeline threats and therefore PHMSA retained the requirement to identify and evaluate threats consistent with § 192.917. The term ''assess'' was changed to ''evaluate'' to avoid confusion with a similar term used in integrity management.

Section 192.620(d)(2), Notifying the Public

INGAA and five pipeline operators would eliminate the requirements in this proposed section. They contended they are unnecessary as they duplicate requirements in existing § 192.616 for public education. They further contended that a dedicated notification, specific to operation at a higher pressure, is not needed. One operator would delete subparagraph (d)(2)(ii) and replace it with a one-time notification before operation under an alternative MAOP begins. This operator believes that the proposed requirement for a continuing information program is excessive, but that a one-time notification could be appropriate.

Response

Because of the higher consequences of operating a pipeline at a higher alternative MAOP (and thus a greater impact radius), PHMSA believes that additional public information is necessary to inform any stakeholders living along the right-of-way of this increase. Where the alternative MAOP pipeline is in an HCA already identified per Subpart O, then no additional notification is necessary beyond what is already required.

Section 192.620(d)(3), Responding to an Emergency in High Consequence Areas

Most industry commenters suggested deleting the requirement that operators be able to remotely open mainline valves. They maintained this requirement is unnecessary as an emergency response measure and is contrary to the operating practice of many gas transmission pipeline operators. Some also opposed a requirement for remote pressure monitoring, indicating that it would be costly to provide and would add no value. AGA commented that the language relating to remote control of valves was too prescriptive and could have the unintended consequence of requiring operators to make their safety procedures less stringent (presumably by allowing remote opening of valves).

GPTC and two pipeline operators questioned the requirement for remote valve operation if personnel response time to the valves exceeds one hour. They argued that the one-hour criterion is arbitrary and not justified by research. One operator suggested that it is also counter to experience. These commenters also noted that it is unclear how the response time is to be applied, from the time of notification of an event, from the time a responder is requested to go to the valve location, or from some other triggering event. GPTC suggested that PHMSA consider a requirement based on mileage, similar to § 192.179. One operator indicated that the need for remote control should be based on risk analysis rather than an arbitrary specified response time.

Response

PHMSA agrees that the proposed requirement that operators be able to remotely open mainline valves is not needed for emergency response. PHMSA agrees that it is more conservative to require local action to open valves that may have been closed in response to an emergency. PHMSA has modified the final rule to eliminate the requirement that operators be able to remotely open valves. PHMSA considers it important to be able to monitor pressure in order to know that valve closure has been effective. PHMSA has retained this requirement.

PHMSA considers a one-hour response time appropriate and reasonable. It provides time to respond to events while limiting the consequences of an extended conflagration. In the final rule, PHMSA has clarified that the one-hour period begins from the time an event requiring valve closure is identified in the control room and is to be determined using normal driving conditions and speed limits.

Section 192.620(d)(4), Protecting the Right-of-way

All commenters except the state pipeline safety regulatory agency and the steel/pipe manufacturers addressed this section. All contended that the requirement to patrol the right-of-way 26 times per year was excessive and that experience indicates that more frequent patrolling does not prevent pipeline events. They maintained that the proposed frequency has no apparent basis other than that it is the patrolling frequency required for hazardous liquid pipelines and that application of a hazardous liquid pipeline frequency to gas transmission lines is inappropriate.

One operator noted that its experience with monthly patrols has demonstrated that there is very little excavation activity during winter and the summer growing season, making patrols then of little value. The commenters' proposals for alternate patrolling intervals varied, with some suggesting intervals that would vary based on the class location. INGAA suggested patrolling every 4½ months and after known events.

INGAA and one pipeline operator suggested deleting the requirement for a soil monitoring plan, because it would be costly and only duplicates other existing requirements.

INGAA and six pipeline operators suggested deleting the requirement to maintain depth of cover. In its place, they would require restoring depth of cover or providing appropriate preventive and mitigation measures only where damage may occur due to loss of cover. They noted that maintaining the original depth of cover is impractical and unnecessary. Normal erosion and other events can reduce depth of cover, but that reduction does not necessarily lead to an increased risk of damage. Action may be needed in limited circumstances and providing other protection in those circumstances may be more effective and less costly than restoring the original depth of cover. One operator suggested that a monitoring/maintaining depth of cover requirement should be driven by events or risk analysis and that discussion in the preamble of the NPRM implied such an approach. This operator suggested allowing engineered solutions in addition to restoring depth of cover.

INGAA and four pipeline operators would delete or relax the requirement for line-of-sight pipeline markers. INGAA noted that discussion at the March 2007 public meeting indicated that such markers add no value. One operator suggested that it would be more effective to emphasize one-call damage prevention in the preamble of the final rule. Another operator noted that installation of such markers is ''non-trivial,'' and that there is no data or analysis supporting the need for them. Yet another operator commented that the intent of the requirement is unclear and suggested that circumstances other than agricultural areas and large bodies of water (exclusions included in the proposed rule) would also make it difficult to install line-of-sight markers (*e.g.*, steep terrain, swamps).

INGAA and five pipeline operators objected to what they characterized as an ''open ended'' requirement to implement national consensus standards for damage prevention. These commenters suggested that the requirements focus on the damage prevention best practices identified by the Common Ground Alliance (CGA) and require that operators implement the CGA best practices that apply to their situation. One operator suggested that operators be allowed to evaluate and choose among CGA practices. Another operator also supported a right to choose, indicating that the CGA guide includes no expectation that operators will adopt all best practices.

INGAA and five pipeline operators objected to the proposed requirement for a right-of-way management plan, because it duplicates existing requirements for damage prevention.

Response

PHMSA has revised the required patrol frequency to once per month, at intervals not to exceed 45 days. The decision to reduce the patrolling frequency from 26 patrols per year was based on further analysis of the value added by the cost of additional patrolling, PHMSA's greater experience with administering special permits, and comments from industry and public advocates supporting risk-based requirements rather than a one-size-fits-all approach. PHMSA believes that the right of way management plan required by § 192.620(d)(4)(vi), coupled with the patrolling requirement, will provide appropriate safety coverage through requiring an operator to develop and implement an array of actions based on the risk of third-party damage to the pipeline. These preventative actions may well include additional patrolling above what is required by this rule in areas that are more heavily-populated or that possess greater chances for third-party activities in the vicinity of a pipeline.

PHMSA has retained the requirement for a soil monitoring program. Gas transmission pipelines are often located in areas that can exhibit unstable soils, such as clay, hills, and mountainous areas. It is important to assure that stresses caused by soil movement do not damage pipelines in these areas with reduced design safety factors. PHMSA recognizes that operators may already address these issues in their damage prevention plans or other operating and maintenance procedures. If so, an additional plan is not required. Operators must be able to demonstrate, during regulatory audits, that soil monitoring is addressed within their procedures.

PHMSA has retained the requirement for line-of-sight pipeline markers. Outside damage is the most significant threat to gas transmission pipelines, resulting in the greatest number of accidents. These accidents occur despite current requirements for pipeline markers. Those requirements in § 192.707 already require that markers be maintained ''as close as practical'' in the areas required to be covered. PHMSA continues to believe that it is important to provide line-of-sight markers for pipelines operating at alternative MAOP in order to reduce the frequency of outside damage. PHMSA supports one-call programs, and regularly takes actions to encourage and foster their use. Still, damage incidents occur. It is important to reinforce the need for using a one-call program by providing visual evidence that a pipeline is located in an area subject to potential excavation.

At the same time, PHMSA recognizes that installation of line-of-sight markers is not feasible in all locations. The rule does not require installation of line-of-sight markings in agricultural areas or large water crossings such as lakes and swamps where line-of-sight markers are not practicable. The marking of pipelines is also subject to FERC orders or environmental permits and local laws/regulations. The rule does not require installation where these other authorities prohibit markers.

PHMSA also retained the requirement for a right-of-way management plan since PHMSA data indicates recurring similarities in pipeline accidents on construction sites where better management of the right-of-way could have prevented the accidents. This provision is not redundant with existing damage prevention program requirements, but requires operators to take further steps to integrate activities under those programs to provide for better protection of the right-of-way.

Section 192.620(d)(5), Controlling Internal Corrosion

INGAA, GPTC, four pipeline operators and the state pipeline safety regulatory agency would require a program to monitor gas quality and to remediate internal corrosion as needed but would delete all the specific requirements in this section. One operator suggested that a program complying with Subpart I is all that is needed. The state regulatory agency noted that the NPRM provided no rationale for more stringent or prescriptive requirements than those recently published as § 192.476.

Two pipeline operators objected to the requirement for filter separators, contending that these devices are not effective for dealing with upsets involving free water and can provide a false sense of security. One suggested that other actions could be required to assure gas quality. Two other operators suggested that properly designed gas separators would be as effective as filter separators.

One operator objected to requirements for cleaning pigs, inhibitors, and sampling of accumulated liquids. Another opposed the requirement for inhibitors. These operators noted that these actions are not needed if gas monitoring confirms no deleterious constituents. They maintained that the requirements are unnecessary and can potentially result in unintended consequences and risks.

AGA contended that operators should be allowed to determine appropriate methods for monitoring gas quality and that these methods need not always require testing by individual operators. AGA believes this is especially true if tariffs and operating experience demonstrate the absence of contaminants. One pipeline operator asked that PHMSA clarify that the required chromatographs are for analysis of corrosive constituents and need not provide complete analysis for heating value or other purposes.

Two pipeline operators suggested that PHMSA define deleterious gas stream constituents of concern. Two pipeline operators suggested that the limits on gas constituents should be deleted or revised based on research and testing. They believe that the proposed limits are not technically justified. One further noted that deleterious effects may result from contaminants acting ''in concert.''

One pipeline operator would revise the requirement for review of an operator's internal corrosion monitoring and mitigation program to annual review because there is no technical justification for quarterly reviews. Another operator suggested that the gas quality requirements be deleted, as they may conflict with tariffs and result in duplicate enforcement. This operator also suggested that sampling intervals be established by reference to section § 192.477 and agreed that a requirement for quarterly review of internal corrosion monitoring programs is excessive.

Response

PHMSA concludes that the proposed requirements do not duplicate or conflict with those in the recently published § 192.476. The latter requirements deal principally with design considerations related to internal corrosion, while those included here address monitoring to determine whether conditions conducive to such corrosion occur. Similarly, § 192.477 only requires monitoring if corrosive gas is present. The requirements included here specify contaminants to be monitored and limits to be achieved. Since § § 192.476 and 192.477 represent the requirements in subpart I related to internal corrosion, PHMSA does not agree that a program complying with subpart I alone is sufficient.

PHMSA has revised the requirement for use of cleaning pigs, inhibitors, and collection of accumulated liquids to apply only in those situations in which corrosive gas is determined to be present. For the particular case of hydrogen sulfide, PHMSA has specified a limit (0.5 grain per hundred cubic feet, 8 parts per million (ppm)) above which this requirement applies.

PHMSA has retained the requirements for gas monitoring. It is important to monitor the gas stream to assure that internal corrosion will not occur or will be identified if corrosion does occur. Continuous monitoring is the most effective way of doing this. PHMSA agrees that monitoring equipment required by this rule is for the purpose of analyzing corrosive gas constituents and need not provide estimates of heating value or other characteristics. Operators can rely on others (*e.g.*, those supplying gas to them) to perform monitoring, but they must assure that such monitoring covers all gas streams and meets the requirements of this rule, including the need for continuous monitoring. PHMSA has also retained the requirement to review the internal corrosion monitoring program quarterly. Such reviews are needed to help assure that upset conditions that could potentially cause internal corrosion are identified and addressed promptly. Annual reviews are insufficient to do this.

PHMSA has revised the limit for hydrogen sulfide to 1.0 grain per hundred cubic feet, or 16 ppm. (PHMSA has also presented this limit in both forms of measurement, as suggested by one commenter). This limit is more consistent with typical tariff limits. At the same time, the final rule requires that additional mitigative actions, including use of cleaning pigs and inhibitors be required when the hydrogen sulfide content exceeds 0.5 grain per hundred cubic feet, as this concentration increases the likelihood of internal corrosion.

The final rule clarifies that deleterious gas stream constituents also include entrained or suspended solids (regardless of size) that are detrimental to the pipeline or pipeline facilities.

Section 192.620(d)(6), Controlling Interferences That Can Impact External Corrosion

Two pipeline operators requested that we clarify that interference surveys are only required where interference is likely, are to be developed using operator judgment, and can be performed using voltage measurements versus ''current.''

Response

PHMSA has clarified the final rule to require that surveys be performed in areas where interference is suspected. Operators should consider the proximity of potential sources of interference, including electrical transmission lines, other cathodic protection systems, foreign pipelines, and electrified railways in deciding where surveys are needed. Operators must conduct surveys capable of detecting the effect of interfering currents, but these surveys need not measure ''current'' directly.

Section 192.620(d)(7), Confirming External Corrosion Control Through Indirect Assessment

INGAA and four pipeline operators requested that this section be revised to require close interval survey (CIS) alone versus one of CIS, direct current voltage gradient (DCVG), or alternating current voltage gradient (ACVG). One of these operators requested clarification that indirect examination is not necessary if additional measures are taken to assure the integrity of the pipeline. Yet another operator suggested that this section be revised to allow other methods of indirect assessment, noting that C–SCAN (which is a current measurement technique) is one possibility that appears to be precluded by the proposed language. All of these commenters plus three additional pipeline operators requested that the timeframe for conducting these examinations be relaxed from six months to one year. They noted that six months may often be impractical because of limitations associated with seasonal weather.

One pipeline operator would delete the proposed requirement for a coating survey of existing pipelines, maintaining that this examination is not needed, since the results of ILI and CIS show that the combination of coating and cathodic protection is working to protect against corrosion. This operator would move the requirement for indirect survey and coating damage remediation to § 192.328 to make it clear that this is a construction requirement applicable to new pipelines only. Another operator also commented that requirements to remediate construction damaged coating should be limited to new pipe only. This operator further requested deleting the proposed requirement to repair all voltage drops classified as moderate or severe by National Association of Corrosion Engineers (NACE), since it is unnecessary and impractical to repair every voltage drop. Another operator commented that operators should be allowed to develop specific repair criteria based on their experience.

INGAA and four pipeline operators would relax the proposed requirement to remediate construction coating damage to require either remediation or appropriate cathodic protection. They suggested that the proposed requirement conflicts with the NACE standard referenced in this section (NACE RP–0502–2002) and that coating remediation is not needed as cathodic protection provides adequate protection for areas affected by coating holidays. Another operator noted that the NACE defect classification guidelines are qualitative and that interpretation differences could result in differing repair expectations.

INGAA and two pipeline operators recommended relaxing the requirement to integrate indirect assessment results with ILI from six months to one year. They believe that more rapid integration is not needed and that the value of quicker integration is not explained in the NPRM. Another operator suggested there is an inconsistency in that paragraph (ii) requires action based on the results of one assessment while paragraph (iii) requires that the results of two assessments be integrated.

INGAA and three pipeline operators would delete the periodic assessment requirements of proposed paragraph (iv). They would move the requirements for location of CIS test points in proposed subparagraph (B) to § 192.328, as they contended these are more appropriate as construction requirements. These commenters would further revise the CIS location requirements to state that a CIS test station must be within one mile of each HCA, versus within each HCA. They contended that it is not practical to require a test station within each HCA, noting that the length of the pipeline in some HCAs may be very short. Another operator would combine subparagraphs (A) and (B).

Response

CIS is a technique to locate areas of poor cathodic protection and is considered a macro tool. Micro tools, such as DCVG or ACVG, must be used to locate small but critical coating holidays. C–SCAN, which is a current measurement technique, is considered a macro tool and will only find large coating holidays. Small coating holidays can be just as critical as large ones, especially in areas where cathodic protection potentials can be depressed. PHMSA considers it important to monitor coating condition. The comments suggesting that macro tools be allowed appear to be based on the premise that small coating holidays are not important as long as cathodic protection continues to protect the pipeline. As discussed above, PHMSA does not agree with this presumption, and here, again, does not agree that either coating or cathodic protection is required; both are needed. PHMSA recognizes that if one accepts the presumption that assuring coating integrity is not important on pipelines subject to cathodic protection, then prompt resolution of coating issues is not important either. Since PHMSA does not accept the premise, PHMSA has not relaxed the proposed timeframes for conducting surveys or integrating results.

In particular, PHMSA does not agree that a one year interval should be allowed to assess coating adequacy. Experience has demonstrated that significant corrosion can occur during very short intervals. PHMSA notes that the proposed requirement potentially extends the period between the beginning of pipeline operation and coating assessment to 18 months—12 months after operation in which cathodic protection must be made operational (§ 192.455(a)(2)) plus the six months allowed here. PHMSA considers this to be the maximum period that should be allowed before determining coating adequacy. Proper planning and scheduling should allow operators to accommodate weather and other scheduling concerns. Operators can delay the start of operation at an alternative MAOP if they cannot schedule coating surveys within six months.

PHMSA's conclusion that coating integrity is important, regardless of the presence of cathodic protection, means that determining coating adequacy is important for existing pipelines as well as new construction. As such, it is not appropriate to move this requirement to a section applicable to new construction only. Further, it is not acceptable to rely on ILI or other assessment methods to identify corrosion after it has occurred. The purpose here is to prevent corrosion. ILI or other assessments are a second level of defense, detecting corrosion after it occurs, but PHMSA does not consider them to obviate the need for actions to prevent the problem from occurring in the first place. CIS is a verified method of determining if all of a segment is protected by appropriate cathodic protection potentials. The use of CIS will allow an operator to find any ''hot spots'' along the pipeline that could cause active corrosion. The CIS will find any depressed locations whereas a test station survey may miss such locations unless they are in close proximity to the test station.

With respect to proximity to a test station, PHMSA agrees that there could be situations in which it may not be practical to locate a test station within an HCA. This could occur, for example, when the HCA is determined by an identified site near the outer radius of the potential impact circle, in which case the length of pipeline in the HCA could be very short (on the order of several feet). Still, PHMSA does not agree that this limitation should be addressed by requiring that a test station be within one mile of an HCA. PHMSA has revised the final rule to require that a test station be located within an HCA if practicable and has retained the proposed requirement that test stations be located at half-mile intervals on pipelines to be operated at alternative MAOP.

Section 192.620(d)(8), Controlling External Corrosion Through Cathodic Protection

INGAA, GPTC and eight pipeline operators considered the requirement to address inadequate cathodic protection readings in six months to be excessive. They also noted that seasonal and land use issues make responding within one year much more reasonable, and suggested the proposed rule be changed accordingly. GPTC and one operator noted that the proposed change is inconsistent with an existing PHMSA interpretation, which states that remediation of inadequate cathodic protection readings is required before the next scheduled monitoring. The operator noted that this is typically one year (not to exceed 15 months), supporting the proposed change to a one-year response in this rule.

INGAA and three pipeline operators objected to the proposed requirement to conduct CISs after remediating cathodic protection problems to evaluate effectiveness. They noted that a CIS is not needed to confirm resolution of many problems (*e.g.*, loss of power, cut cable, short). They agreed that operators should confirm that remedial action was appropriate and effective, but contended that a requirement to perform a CIS after any remedial action is unjustified and excessive.

Response

As discussed above, experience has shown that significant corrosion damage can occur over brief periods. Pipelines operating at an alternative MAOP have less margin for corrosion than do pipelines operating at MAOP determined in accordance with § 192.111. Cathodic protection is an important protection against corrosion damage, as recognized by those commenting on this rule. PHMSA does not agree that it is acceptable to wait one year to resolve known cathodic protection problems. At the same time, PHMSA recognizes that there may be situations in which remediation in six months is not practical. PHMSA has revised the final rule to require operators to notify the PHMSA Regional Office where a pipeline is located (and states where appropriate) if inadequate cathodic protection readings are not addressed within six months, providing the reason for the delay and a justification that the delay is not detrimental to pipeline safety. This will allow regulators to review the circumstances of each situation in which resolution takes longer than six months and to make a judgment of adequacy based on the particular circumstances.

PHMSA agrees that it is not necessary to perform a complete CIS again to verify that any remedial action has addressed an identified problem. Commenters are correct in noting that problems such as a cut cable or short can result in inadequate cathodic protection readings and that correction of these problems can be verified without a new CIS. PHMSA has revised the final rule to require that operators verify that corrective action is adequate, leaving the means to do so up to the operator's discretion and judgment.

Section 192.620(d)(9), Conducting a Baseline Assessment of Integrity

Proposed § 192.620(d)(9)(iii) would require that headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portions that cannot accommodate ILI tools be assessed using DA. INGAA and four pipeline operators objected to this requirement as unjustified and inconsistent with previous special permits. They suggested a change that would also allow pressure testing or development and implementation of a corrosion control plan. They further noted that these segments may be designed to § 192.111, may not operate at an alternative MAOP, and thus may not be subject to this section.

One operator also noted that there may be portions of a pipeline facility that will not be operated at an alternative MAOP. The operator requested clarification that the proposed requirements apply only to segments that are intended to operate at an alternative MAOP. This commenter also suggested an exclusion for small pipe and equipment to be consistent with a frequently asked question (FAQ) #84 on the gas transmission integrity management Web site (*http://primis.phmsa.dot.gov/gasimp/*). (The FAQ addresses whether small-diameter piping, *e.g.*, within a compressor station, must be considered to be part of an HCA. It states that potential impact radii should be calculated, and a determination made as to whether an HCA exists, based on the diameter of individual pipeline segments.)

The same operator would also allow the baseline assessment for an existing pipeline segment to be conducted before operation at an alternative MAOP begins but within the assessment interval specified in subpart O rather than the proposed two years. The operator contended that there is no scientific basis to require assessments every two years, particularly if a pipeline segment is being managed under subpart O.

Response

PHMSA agrees that assessment of small-diameter station piping can be performed using pressure testing and has revised the final rule accordingly. PHMSA does not agree that it is acceptable for such a non-piggable pipeline to be under an unspecified corrosion control plan rather than to be subject to assessment.

PHMSA agrees that FAQ #84 addresses the same pipe, but does not agree that it is a precedent for determining whether a small-diameter pipeline requires assessment. An FAQ is advisory in nature and this FAQ provides guidance in the context of integrity management, on whether this pipeline should itself be determined to be an HCA. For this rule, additional assessment requirements are being applied to a pipeline operating at an alternative MAOP, regardless of whether it is in an HCA. PHMSA has revised this paragraph to clarify that it applies only to a pipeline operating at an alternative MAOP. Small-diameter pipe within a station that does not operate at alternative MAOP would not be affected by these requirements. PHMSA agrees that small-diameter pipe, headers, meter stations, compressor stations, river crossings, road crossings and any other pipeline facility can be designed and constructed in accordance with § 192.111 criteria and then would not be subject to alternative MAOP integrity assessment criteria such as ILI and DA.

PHMSA does not agree that it is acceptable to rely on assessments that may have been performed within the time intervals allowed by subpart O. Under subpart O, it may have been nearly ten years (in some limited cases 15 years) since a complete assessment was performed. PHMSA considers that more current information is needed before deciding that it is acceptable to operate a pipeline at an alternative MAOP. PHMSA considers the two-year period reasonable for operators to schedule and perform assessments that will result in more current information when the operating stresses on the pipeline are increased.

Section 192.620(d)(11), Making Repairs

INGAA and three pipeline operators noted that the repair requirements in the proposed rule are inconsistent with subpart O and, they believe, overly conservative and burdensome. INGAA contended that the proposed requirements will be unachievable in many cases. Another operator commented that the repair criteria proposed for Class 2 and 3 areas are extremely conservative and unnecessary.

Two pipeline operators suggested that this section be replaced with a reference to subpart O, since they believe the repair requirements of that subpart and ASME/ANSI B31.8S (referenced in subpart O) are appropriate for pipelines operating at 80 percent SMYS.

Two pipeline operators noted that the dent repair criteria in subparagraph (i)(A) are those for new pipelines following construction and before commissioning and suggested that these are inappropriate for existing pipelines. One of these operators contended that the repair criteria for existing pipelines should be as in subpart O, § 192.933(d). The other noted that there is experience demonstrating that plain dents of much greater than two percent of pipe diameter in depth are not a threat to pipeline integrity.

Three pipeline operators proposed alternative repair criteria. They would require immediate repair of defects for which the failure pressure is 1.1 times the revised alternative MAOP. They would require repairs within one year for defects for which the failure pressure is 1.25 times the MAOP. They contended that these criteria are consistent with those in subpart O and ASME/ANSI B31.8S and are appropriate. They believe that the criteria in the proposed rule represent an inappropriate shortening of the time allowed to address identified defects.

Proposed subparagraph (i)(A) would require that an operator ''use the most conservative calculation for determining remaining strength'' of a pipeline segment containing an identified anomaly. INGAA and four pipeline operators contended that this requirement could be interpreted to require that multiple calculations be performed, using all available tools/models, to determine which is most conservative. They believe this is inappropriate and that operators should use the most appropriate calculational tool.

Response

PHMSA recognizes that the repair criteria in this rule are more stringent than those in subpart O. PHMSA considers this appropriate. A pipeline that will operate under alternative MAOP is subject to more stress and has less wall thickness margin to failure than most pipelines operating under subpart O (with the exception of some grandfathered lines). Most pipelines that will be subject to this rule will be new pipelines. PHMSA's repair criteria use safety factors similar to those for the design of a new pipeline based upon class location design factors, and are intended to maintain overall safety margins at corrosion anomalies based upon all operating and environmental factors. The net effect of the QA and O&M requirements in this rule for construction and operation of those pipelines covered by the rule will likely result in the need for few repairs, even with these stricter criteria. PHMSA considers these factors of safety a key element in assuring public safety on higher MAOP pipelines.

Similarly, PHMSA disagrees that failure pressures of 1.1 and 1.25 times MAOP are appropriate for immediate and one-year (respectively) repairs for all class locations. Class 2 and Class 3 locations require more stringent safety factors for anomaly evaluation and remediation due to the higher consequences to public safety that may be caused by a leak or rupture of the pipeline. As discussed extensively throughout this response to comments, pipelines to be operated at alternative MAOP will operate at higher pressures with less margin to failure than most pipelines. Use of repair criteria different from and requiring repairs quicker than in subpart O is appropriate.

With respect to dents, the repair criteria of § 192.309(b) apply only for dents found during construction baseline assessments (*i.e.*, for new pipelines). PHMSA notes that this section already requires repair of two percent dents for pipelines over 12¾ inches in diameter. The criteria for repairing dents on existing pipelines and subsequent assessments on new pipelines and existing pipelines are in § 192.933(d).

PHMSA acknowledges that an operator cannot know which method for calculating remaining strength is most conservative without applying each method. Questions have been raised concerning the applicability of some current methods for calculating the remaining strength of high-strength pipelines and greater depth corrosion anomalies in all field operating conditions. PHMSA is planning to sponsor a public meeting to review these questions and help determine the adequacy of existing calculational methods for the kind of high-strength pipe that will operate at alternative MAOP. PHMSA will propose changes to this rule at a later date, if appropriate.

C.3. Comments on Regulatory Analysis

One pipeline operator submitted two comments relating directly to the regulatory analysis supporting the proposed rule.

First, the operator contends that the expected reduction in expenditure for compressors for new pipelines should not be claimed as a benefit. The operator contended that reductions may be realized for existing pipelines that operate at an alternative MAOP but not for new pipelines.

Second, the operator contended that PHMSA should not state that new design factors will result in increased capacity for new pipelines and noted that new pipelines will be designed for the required capacity. The effect of the proposed rule will be to reduce costs by allowing the use of thinner-walled pipe.

Response

PHMSA understands that the operator's statement that new pipelines will be designed for the required capacity is at the heart of both of these comments. The operator essentially contended that new pipelines that will be so designed will see no increased capacity or change in costs as a result of this rule. PHMSA does not agree. New pipelines designed with alternative MAOPs should mean less cost to the customer/public, and thus a benefit to society, due to less capital costs for the same natural gas through-put/flow volumes. Existing pipelines will be able to carry up to an additional 11 percent natural gas flow volumes based upon the overall design of the pipeline and compressor stations with this alternative MAOP.

In the absence of this rule (or of obtaining a special permit to operate at alternative MAOP) new pipelines would need to be designed for less capacity or at increased cost (due to the need to use thicker-walled pipe). Thus, there is a societal benefit to this rule in that it will allow more gas to be transported at a higher standard of safety for a given dollar investment. The companies designing and constructing new pipelines under this rule will also realize a benefit, since in the absence of this rule (or a special permit addressing the same issues) they would either have to carry less gas or incur additional costs. PHMSA has revised the discussion in the regulatory analysis to help make this point more clearly.

D. Consideration by the Technical Pipeline Safety Standards Committee (TPSSC)

The TPSSC met on June 10, 2008, and considered the proposed rule. During this discussion, PHMSA provided its preliminary views of changes that might be made in response to comments submitted in response to the proposed rule.

PHMSA informed the TPSSC that some changes would be made in rule structure, moving some requirements to other sections for better applicability (*e.g.*, requirements applicable to existing pipelines would be moved from the section of the rule in which construction requirements are located).

PHMSA informed the TPSSC it has not adopted the suggestion by the state pipeline safety regulatory agency that submitted comments supported by its director (a member of the committee) to place the rule in a separate subpart, as that is counter to the general structure of part 192.

TPSSC members expressed concern, as did many commenters, about reliance on individual standards or tests. In the final rule, PHMSA has allowed use of equivalent methods (*e.g.*, for the macro etch test, hardness limits, type of crack arrestors).

PHMSA informed the TPSSC that the vast majority of commenters objected to the proposed requirement for mill hydrostatic inspection tests of longer duration and that, as a result, that change would not be included in the final rule. PHMSA also noted that most industry commenters noted that the proposed rule did not make allowances for changes in class location after a pipeline is in service, as do the existing regulations.

The anomaly repair requirements were of concern to industry, who asserted the requirements were overly conservative. PHMSA informed the TPSSC that this issue is complicated by questions recently raised concerning the applicability of remaining strength calculational methods to high-stress pipelines and that resolving those questions before completing this rule would delay issuance of the rule. PHMSA stated that it would conduct a public meeting later this year to address the global issue of appropriate calculational methods and repair criteria. Changes to this or other regulations requiring pipeline repair may be appropriate following that workshop.

Treatment of existing and pending applications for special permits was a significant concern for several members of the TPSSC. PHMSA noted that the standards in the final rule are very similar to those applied in recent special permits. PHMSA reported its intention to continue to review pending special permit applications while this rulemaking proceeded. Upon issuance of the final rule, PHMSA expects operators desiring to use alternative MAOP to comply with the rule. PHMSA will examine special permits that have already been granted, as appropriate, to determine if any modifications are needed in light of the outcome of this rulemaking.

Subsequent to discussion, the TPSSC voted unanimously to find the proposed rule and supporting regulatory evaluations technically feasible, reasonable, practicable, and cost effective, subject to incorporation of the changes discussed by PHMSA during this meeting. A transcript of the meeting is available in the docket.

E. The Final Rule

Revisions described in this section are changes to the corresponding section in the proposed rule.

E.1. In General

The rule adds a new section (§ 192.620) to Subpart L—Operations. This new section explains what an operator would have to do to operate at a higher MAOP than currently allowed by the design requirements. Among the conditions set forth in new § 192.620 is the requirement that the pipeline be designed and constructed to more rigorous standards. These additional design and construction standards are set forth in two additional new sections (§§ 192.112 and 192.328) located in Subpart C—Pipe Design and Subpart G—General Construction Requirements for Transmission Lines and Mains, respectively. In addition, the rule makes necessary conforming changes to existing sections on incorporation by reference (§ 192.7), change in class location (§ 192.611), and maximum allowable operating pressure (§ 192.619).

E.2. Amendment to § 192.7—Incorporation by Reference

The rule adds ASTM Designation: A 578/A578M—96 (Re-approved 2001) ''Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications'' to the documents incorporated by reference under § 192.7. This specification prescribes standards for ultrasonic testing of steel plates. It is referenced in new § 192.112.

The rule also revises the description of item (B)(1) in the table of § 192.7(c)(2), API 5L ''Specification for Line Pipe,'' (43rd edition and errata), 2004, to indicate that it is referenced in new § 192.112 in addition to the locations at which it was referenced previously.

E.3. New § 192.112—Additional Design Requirements

The rule adds a new section to Subpart C—Pipe Design in 49 CFR Part 192. The new section, § 192.112, prescribes additional design standards required for the steel pipeline to be qualified for operation at an alternative MAOP based on higher stress levels. These include requirements for rigorous steel chemistry and manufacturing practices and standards. Pipelines designed under these standards contain pipe with toughness properties to resist damage from outside forces and to control fracture initiation and growth. The considerable attention paid to the quality of seams, coatings, and fittings will prevent flaws leading to pipeline failure. Unlike other design standards, § 192.112 applies to a new or existing pipeline only to the extent that an operator elects to operate at a higher alternative MAOP than allowed in current regulations.

Paragraph (a) sets high manufacturing standards for the steel plate or coil used for the pipe. The pipe would be manufactured in accordance with Level 2 of API 5L, with the ratio between diameter and wall thickness limited to prevent the occurrence of denting and ovality during construction or operation. Improved construction and inspection practices addressed elsewhere in this rule also help prevent denting and ovality.

Paragraph (a) has been revised in response to comments to add an alternative method (and applicable limit) for determining equivalent carbon content. In addition, the proposed limit on equivalent carbon content of 0.23 (Pcm formula) has been raised to 0.25. Several comments suggested deleting the limit on the ratio of pipe D/t, but this limit has been retained, as discussed above.

Paragraph (b) addresses fracture control of the metal. First PHMSA expects the metal would be tough; that is, deform plastically before fracturing. Second, the pipe would have to pass several tests designed to reduce the risk that fractures would initiate. Third, to the extent it would be physically impossible for particular pipe to meet toughness standards under certain conditions, crack arrestors would have to be added to stop a fracture within a specified length.

Paragraph (b) has been revised to allow alternate means of crack arrest. This can include the ''mechanical'' means included in the proposed rule but can also include other design features such as use of composite sleeves, spacing, increases in wall thickness at appropriate distances, etc. This paragraph has also been revised to clarify the factors that must be considered by an operator in evaluating resistance to fracture initiation and to make clear that this evaluation is intended to address the full range of relevant parameters to which the pipe will be exposed over its operating lifetime. If unexpected situations or a change in operating conditions result in a change in these parameters during operation, such that they are outside the bounds of those analyzed, operators will be required to review and update their evaluation and implement remedial measures to assure continued resistance to fracture initiation.

Paragraph (c) provides tests to verify that there are no deleterious imperfections in the plate or coil. The macro etch test will identify flaws such as segregation that impact the plate or coil quality. Surface and interior flaws such as laminations and cracking will show up in UT testing.

This paragraph has been revised, in response to comments, to change ''mill inspection program'' to an internal quality management program designed to eliminate or detect defects or inclusions that can affect pipe quality and to require that such a program be implemented at all mills involved in the process of casting the steel, rolling it into plate, coil or skelp, and the process of manufacturing the steel into line pipe. The revised paragraph also includes an alternative to the macro etch test and reference to an additional standard for UT testing the plate, coil, skelp or manufactured line pipe. (Equivalent standards are also still allowed.)

In addition to the quality of the steel, the integrity of a pipe depends on the integrity of the seams. Paragraph (d) provides for a QA program to assure tensile strength and toughness of the seams so that they resist breaking under regular operations. Hardness and UT tests after mill hydrostatic tests would ensure that the seams did not have defects or imperfections that were exposed by the stresses of the hydrostatic test pressure.

Paragraph (e) requires a mill pressure test for new pipe at a higher hoop stress than required by current regulations. The mill test is used to discover flaws introduced in manufacturing. Because the pipeline will be operated at a higher stress level, the more rigorous mill test is needed to match (or exceed) the level of safety provided for pipelines operated at less than 72 percent of SMYS. Paragraph (e) has been revised to eliminate the proposed extension of the duration of mill pressure tests.

Paragraph (f) sets rigorous standards for factory coating designed to protect the pipeline from external corrosion. A QA program must address all aspects of the application of coating that will protect the pipeline. This would include applying a coating resistant to damage during transportation and installation of the pipe and examining the coated pipeline to determine whether the applied coating is uniform and without defects. Thin spots or voids/holidays in the coating make it more likely for corrosion to occur and more difficult to protect the pipeline cathodically.

Paragraph (g) requires that factory-made fittings, induction bends, and flanges be certified as to their serviceability and quality. In addition the CE of these fittings and flanges would need to be documented, so that welding procedures could require pre-heat temperature to eliminate welding defects.

Paragraph (g) has been revised to clarify that the serviceability certification must address properties such as chemistry, minimum yield strength, and minimum wall thickness to meet design conditions. PHMSA expects that valves, flanges and fittings should be rated based upon the required specification rating class for the alternative MAOP and the operator to have documented mill reports with chemistry, minimum yield strength, and minimum wall thickness. Where specialty bends such as hot bends are used for pipeline segments operating per the alternative MAOP, PHMSA expects the operator to address properties such as chemistry, minimum yield strength, minimum wall thickness and other properties that the hot bending process could alter.

Paragraph (h) requires compressor design to limit the temperature of downstream pipe operating at an alternative MAOP to a specified maximum. Higher temperature can damage pipe coating. An exception to the specified maximum is allowed if testing of the coating shows it can withstand a higher temperature. The testing duration, qualification procedures and results must be of sufficient length and rigor to detect coating integrity issues for the type coating, operating and environmental conditions on the pipeline. Operators may also rely on a long-term coating integrity monitoring program to justify operation at higher temperatures, provided the program is submitted to and reviewed by PHMSA.

Paragraph (h) has been revised to clarify the allowed exception. Testing must address coating adhesion and condition as well as cathodic disbondment. Operators are required to submit their test results, including the acceptance criteria they applied to assure themselves that these characteristics are adequate, to the appropriate PHMSA regional office(s) and applicable state regulatory authorities at least 60 days prior to operating at elevated temperature. (State notification applies when the pipeline is located in a state where PHMSA has an interstate agent agreement, or an intrastate pipeline is regulated by that state.)

A subtle, but important, change has also been made in the language in this paragraph. As proposed, the discharge temperature of compressor stations would have been limited to the specified temperature. As revised, the temperature of the nearest downstream pipeline segment to operate at alternative MAOP must be limited. For situations in which the pipeline segment at the discharge of a compressor station operates at alternative MAOP, there is no practical difference. The revised language, however, allows pipeline operators to implement an alternative approach in which they would use pipe operating at conventional MAOP from the discharge of a compressor station downstream to the point at which pipe temperature will drop to the specified limit. This may provide an alternative for situations in which it may be difficult to limit the compressor station discharge to the specified limit (*e.g.*, southern locations on hot summer days). Gas coolers may be installed at compressor stations on pipelines operating per the alternative MAOP that need to operate above 120 degrees Fahrenheit. Gas cooling at compressor stations is a long standing method for most operators to reduce gas pipeline temperatures.

E.4. New § 192.328—Additional Construction Requirements

The rule also adds a new section to Subpart G—General Construction Requirements for Transmission Lines and Mains. The new section, § 192.328, prescribes additional construction requirements, including rigorous QC and inspections, as conditions for operation of the steel pipeline at higher stress levels. Unlike other construction standards, § 192.328 would apply to a new or existing pipeline only to the extent that an operator elects to operate at a higher alternative MAOP than allowed in current regulations.

Paragraph (a) requires a QA plan for construction. QA, also called QC, is common in modern pipeline construction. Activities such as lowering the pipe into the ditch and backfilling, if done poorly, can damage the pipe and coating. Other construction activities such as nondestructive examination of girth welds, if done poorly, will result in flaws remaining in the pipeline or failures during hydrostatic testing or while in gas service. Using a QA plan helps to verify that the basic tasks done during construction of a pipeline are done correctly.

Field application of coating is one of these basic tasks to be covered in a QA plan. During the course of analyzing requests for special permits, PHMSA discovered field coatings at one construction site which were applied at lower temperature than needed for good adhesion to the pipe. Because coating is so critical to corrosion protection, paragraph (a) requires quality assurance plans to contain specific performance measures for field coating. Field coating must meet substantially the same standards as coating applied at the mill and the individuals applying the coating must be appropriately trained and qualified.

Installation of the pipe into the ditch and backfilling of the pipe are critical operations. PHMSA has found that construction and inspection lapses during the backfilling of the pipe have resulted in pipe denting and coating damage. Sometimes during backfilling of the pipe there are design requirements for the installation of other engineered items such as concrete weights at creek and water saturated soil areas. The proper installation of these types of engineered items is critical to ensure that the pipe and coating are not damaged and the item is installed as required in the specifications. PHMSA has found operator lapses in this critical QC aspect of pipeline construction.

Paragraph (b) requires non-destructive testing of all girth welds. Although past industry practice sometimes has been to non-destructively test only a sample of girth welds, no alternative exists for verifying the integrity of the remaining welds. The initial pressure testing once construction is complete does not normally detect flaws in girth welds unless the girth weld is cracked, has severe lack of penetration or is under undue tension stresses, which would be indicative of systemic problems on the pipeline. PHMSA believes that most modern pipeline construction projects include non-destructive testing of all girth welds. However, because the regulations do not require testing of all girth welds, an operator's records for pipelines already in operation may not be complete on 100 percent of girth welds. To account for this, proposed paragraph (b) would have required testing records for only 95 percent of girth welds on existing segments. This requirement has been retained, but proposed paragraph (b) has been moved to new § 192.620, as it applies to existing pipelines. This section addresses pipeline construction.

Paragraph (c) requires deeper burial of segments operated at higher stress level. A greater depth of cover decreases the risk of damage to the pipeline from excavation, including farming operations.

Paragraph (d) addresses the results of the initial strength test and the assurance these results provide that the material in the pipeline is free of pre-operational flaws which can grow to failure over time. Since the initial strength test is a destructive test, it only detects flaws that would fail at the test pressure. This could leave in place smaller flaws. To prevent this from occurring, the proposed paragraph would have disqualified any segment which experienced a failure during the initial strength test indicative of flaws in the material. Most commenters objected to this provision as too restrictive. They noted that failures can be isolated and that it was unreasonable to preclude an entire pipeline segment from operation at alternative MAOP because of a single failure. This paragraph has been revised to allow conduct of a root cause examination of a failure, including metallurgic examination of the failed pipe, as a way of justifying qualification of the pipeline segment. If that examination determines that the cause of the failure is not systemic, then the pipeline segment would not be disqualified from alternative MAOP operation. Operators must report the results of their root cause evaluation to regulators (PHMSA Regional Office or applicable state regulatory authorities). Review of these analyses by pipeline safety regulators will provide oversight for operator conclusions regarding the non-systemic nature of a failure.

Proposed paragraph (e) addressed cathodic protection on an existing segment. This paragraph has been moved to new § 192.620.

Paragraph (e) (proposed as paragraph (f)) addresses electrical interference for new segments. During construction, sources of electrical interference which can impair future cathodic protection or damage the pipe prior to placing cathodic protection in service need to be identified. Addressing interference at this time supports better corrosion control. Operators will need to coordinate with electric transmission line operators prior to pipeline construction to identify locations of grounding structures and power line currents and voltages and their effect on the pipe. The additional O&M requirements of new § 192.620(d)(6) require operators electing to operate existing pipelines at higher stress levels to address electrical interference prior to raising the MAOP.

E.5. Amendment to § 192.611—Change in Class Location: Confirmation or Revision of Maximum Allowable Operating Pressure

The proposed rule did not include a provision to amend this section. Commenters pointed out that this section addresses changes in class location (*e.g.*, increase in population density near the pipeline) during operation. The existing requirements allow continued operation at pressures higher than would be required for new pipe installed in the new class location, provided pressure testing has been performed at appropriate pressures. The commenters noted that without addressing operation at alternative MAOP in this section, the regulations would effectively rescind the authorization provided by this rule to operate at higher pressure whenever there was a change in class location.

PHMSA agrees that this result was not intended. This section has been revised to include provisions for pipelines operating at alternative MAOP substantially the same as those already provided for existing pipelines. Operation at higher alternative pressures can continue after a class location change, again provided that the pipeline has been tested at appropriate pressures and is not an alternative MAOP operating in a Class 3 location that is upgraded to a Class 4 location. The limits on hoop stress included in this section have been revised to reflect the higher hoop stress that will be experienced by a pipeline at alternative MAOP.

E.6. Amendment to § 192.619—Maximum Allowable Operating Pressure

The final rule amends existing § 192.619 by adding a new paragraph (d) providing an additional means to determine the alternative MAOP for certain steel pipelines. In addition, the rule makes conforming changes to existing paragraph (a) of the section.

E.7. New § 192.620—Operation at an Alternative MAOP

The final rule adds a new section, § 192.620, to subpart L of part 192, to specify what actions an operator must take in order to elect an alternative MAOP based on higher operating stress levels. The rule applies to both new and existing pipelines.

E.7.1. § 192.620(a)—Calculating the Alternative MAOP

Paragraph (a) describes how to calculate the alternative MAOP based on the higher operating stress levels. Qualifying segments of pipeline would use higher design factors to calculate the alternative MAOP. For a segment currently in operation this would result in an increase in MAOP. No changes were proposed in the design factors used for segments within compressor or meter stations or segments underlying certain crossings. PHMSA expects new pipelines operating per the alternative MAOP to have road/railroad crossings, fabrications, headers, mainline valve assemblies, separators, meter stations and compressor stations designed and operated per existing design factors in § 192.111.

Paragraph (a) has been revised to include new design factors for compressor/meter stations or segments underlying certain crossings. These factors apply to facilities in existence prior to the effective date of this rule. Commenters pointed out that compressor stations for existing pipelines have been designed and that failure to allow alternative design factors for them could effectively preclude operation at alternative MAOP for the existing pipelines of which they are a part. PHMSA agrees this was not our intent. The additional risk associated with use of slightly higher design factors for these facilities is marginal. At the same time, there is little additional cost associated with designing stations/crossings/fabrications/headers for future pipelines to serve at the desired MAOP using existing design factors in § 192.111(b), (c), and (d). The rule includes no alternative design factors for these facilities in future pipelines, and operators must use the existing requirements.

E.7.2. § 192.620(b)—Which Pipeline Qualifies

Paragraph (b) describes which segments of new or existing pipeline are qualified for operation at the alternative MAOP. The alternative MAOP is allowed only in Class 1, 2, and 3 locations. Only steel pipelines meeting the rigorous design and construction requirements of §§ 192.112 and 192.328 and monitored by supervisory data control and acquisition systems qualify. Mechanical couplings in lieu of welding are not allowed. Although the special permits did not expressly mention mechanical couplings, PHMSA would not have granted a special permit if the pipeline involved had mechanical couplings.

As proposed, paragraph (b) would have excluded from consideration any existing pipeline that had experienced a failure indicative of materials concerns. This provision has been revised to allow root cause analysis to determine if the failure is indicative of a systemic problem and to preclude use of an alternative MAOP only if a failure is determined to be systematic in nature. Results of the analysis must be reported to regulators (PHMSA Regional Office or applicable state regulatory authorities). This is essentially the same change made for new pipelines in new § 192.328(d), as described above. Paragraph (b) has also been revised to include the requirement that 95 percent of girth welds must have been examined for existing pipelines to operate at alternative MAOP. This requirement was moved from proposed § 192.328(e), as discussed above.

E.7.3. §§ 192.620(c)(1), (2), and (3)—How an Operator Selects Operation Under This Section

Paragraph (c)(1) requires an operator to notify PHMSA, and applicable state pipeline safety regulators, when it elects to establish an alternative MAOP under this section. This notification must be provided at least 180 days prior to commencing operations at the alternative MAOP established under this section. This will provide PHMSA and states sufficient time for appropriate inspection which may include checks of the manufacturing process, visits to the pipeline construction sites, analysis of operating history of existing pipelines, and review of test records, plans, and procedures.

Paragraph (c)(3) 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 O&M procedures to include the more rigorous additional O&M requirements. In addition, a senior executive must certify that the operator has reviewed its damage prevention program in light of best practices, such as CGA 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.

E.7.4. § 192.620(c)(4)—Initial Strength Testing

Paragraph (c)(4) addresses initial strength testing requirements. In order to establish the MAOP under this section, an operator must perform the initial strength testing of a new segment at a pressure at least as great as 125 percent of the MAOP in Class 1 locations and 150 percent in Class 2 and 3 locations. Since an existing pipeline was previously operated at a lower MAOP, it may have been initially tested at a pressure less than these levels. If so, paragraph (c) allows the operator to elect to conduct a new strength test in order to raise the MAOP.

E.7.5. § 192.620(c)(5)—Operation and Maintenance

Paragraph (c)(5) requires an operator to comply with the additional operating and maintenance requirements of § 192.620(d). An operator must comply with these additional requirements if the operator elects to calculate the alternative MAOP for a segment under § 192.620(a) and notifies PHMSA of that election.

E.7.6. § 192.620(c)(6)—New Construction and Maintenance Tasks

Paragraph (c)(6) addresses the need for competent performance of both new construction, and future maintenance activities, to ensure the integrity of the segment. PHMSA now requires operators to ensure that individuals who perform pipeline O&M activities are qualified. Paragraph (c)(6) requires operators seeking to operate at the allowable higher operating stress levels to treat construction tasks as if they were covered by subpart N, ''Qualification of Pipeline Personnel.'' Subpart N (commonly known as OQ) specifies training and qualification requirements applicable to tasks that meet a four-part test in § 192.801(b). Operations and maintenance tasks on the pipeline meet this test, and it is the requirements in subpart N that will govern training and qualification of personnel performing these tasks on a pipeline to be operated at an alternative MAOP. Construction tasks typically do not meet the four-part test and are not covered under subpart N. As proposed, paragraph (c)(6) (then designated (c)(5)) would have required operators to take other actions to assure qualification of personnel performing construction tasks on a pipeline intended to operate at alternative MAOP. Commenters noted that the proposed requirements were vague and subject to interpretation and suggested that PHMSA, instead, rely on the known requirements of subpart N. This paragraph has been modified, in response to these comments, to require that the requirements of subpart N be applied to construction tasks for a pipeline intended to operate at alternative MAOP regardless of the four-part test in § 192.801(b).

E.7.7. § 192.620(c)(7)—Recordkeeping

Paragraph (c)(7) specifies recordkeeping requirements for operators electing to establish the MAOP under this section. Existing regulations, such as §§ 192.13, 192.517(a), and 192.709, already require operators to maintain records applicable to this section. New § 192.620 is in subpart L. Because the additional requirements in this section address requirements found in other subparts of part 192, the recordkeeping requirements could cause confusion. For example, § 192.620(d)(9) requires a baseline assessment for integrity for a segment operated at the higher stress level regardless of its potential impact on an HCA. Section 192.947, in subpart O, requires operators to maintain records of baseline assessments for the useful life of the pipeline. Section 192.709 requires an operator to retain records for an inspection done under subpart L for a more limited time. Accordingly, this paragraph clarifies the need to maintain all records demonstrating compliance with all alternative MAOP requirements for the useful life of the pipeline.

E.7.8 § 192.620(c)(8)—Class Upgrades

Paragraph (c)(8) allows pipelines in Class 1 and 2 to be upgraded one class when class changes occur per § 192.611. This paragraph precludes operation of pipeline in Class 4 at alternative MAOP.

E.8. § 192.620(d)—Additional Operation and Maintenance Requirements

Paragraph (d) sets forth ten operating and maintenance requirements that supplement the existing requirements in part 192. Currently § 192.605 requires an operator to develop O&M procedures to implement the requirements of subparts L and M. Since § 192.620(d) is in subpart L, an operator must develop and follow the O&M procedures developed under this section. These include requirements for an operator to evaluate and address the issues associated with operating at higher pressures. Through its public education program, an operator would inform the public of any risks attributable to higher pressure operations. The additional operating and maintenance requirements address the two main risks the pipelines face, excavation damage and corrosion, through a combination of traditional practices and integrity management. Traditional practices include cathodic protection, control of gas quality, and maintenance of burial depth. Integrity management includes internal inspection on a periodic basis to identify and repair flaws before they can fail. The additional O&M and management requirements are discussed in more detail below.

E.8.1. § 192.620(d)(1)—Threat Assessments

Paragraph (d)(1) requires an operator to identify and evaluate threats to the pipeline consistent with the similar procedures done under integrity management to address the risks of operating at an increased stress level.

E.8.2. § 192.620(d)(2)—Public Awareness

Paragraph (d)(2) requires an operator to include any people potentially impacted by operation at a higher stress level within the outreach effort in its public education program required under existing § 192.616. In order to identify this population, an operator would use a broad area measured from the centerline of the pipe plus, in HCAs, the potential impact circle recalculated to reflect operation at a higher operating stress level. This is intended to get necessary information for safety to the people potentially impacted by a failure.

E.8.3. § 192.620(d)(3)—Emergency Response

Paragraph (d)(3) addresses the additional needs for responding to emergencies for operation at higher operating stress levels. Consistent with the conditions imposed in the special permits, and past experience with response issues, the paragraph requires methods such as remote control valves to provide more rapid shut-down in the event of an emergency.

E.8.4. § 192.620(d)(4)—Damage Prevention

Paragraph (d)(4) addresses one of the major risks of failure faced by a pipeline, damage from outside force such as damage occurring during excavation in the right-of-way. Although the improved toughness of pipe reduces the risk of damage, it does not prevent it and additional measures are appropriate for pipelines operating at higher operating stress levels. This paragraph adds several new or more specific measures to existing requirements designed to prevent damage to pipelines from outside force.

The first more specific measure, in paragraph (d)(4)(i), addresses patrolling, required for all transmission pipelines by § 192.705. More frequent patrols of the right-of-way prevent damage by giving the operator more accurate and timely information about potential sources of ground disturbance and other outside force damage. These include both naturally occurring conditions, such as wash outs, and human activity, such as construction in the vicinity of the pipeline. The requirement is for patrols to be made monthly, at intervals not to exceed 45 days. The patrolling requirement along with other right-of-way requirements including line-of-sight markers, use of national consensus standards, and the right-of-way management plan comprise a multi-faceted approach to protecting the pipeline.

Other more specific or new measures to address damage prevention include developing and implementing a plan to monitor and address ground movement, a requirement of paragraph (d)(4)(ii). Ground movement such as earthquakes, landslides, soil erosion, and nearby demolition or tunneling can damage pipelines. Since pipelines near the surface are more likely to be damaged by surface activities, paragraph (d)(4)(iii) requires an operator to maintain the depth of cover over a pipeline or provide alternative protection. Line-of-sight markers alert excavators, emergency responders, and the general public of the presence and general location of pipelines. Paragraph (d)(4)(iv) requires these markers both to improve damage prevention and to enhance public awareness.

Damage prevention programs are improving because of the work being done by the CGA, a national, non-profit educational organization dedicated to preventing damage to pipelines and other underground utilities. The CGA has compiled best practices applicable to all parties relevant to preventing damage to underground utilities and actively promotes their use. Paragraph (d)(5)(v) requires operators electing to operate at higher stress levels to evaluate their damage prevention programs in light of industry best practices, such as those developed by CGA. An operator must identify the practices applicable to its circumstances and make appropriate changes to its damage prevention program. This approach is consistent with annual reviews of O&M programs under § 192.605. An operator must include in the certification required under § 192.620(c)(1) that the review and upgrade have occurred.

Paragraph (d)(4) also requires the preparation of a right-of-way management plan. In the past several years, PHMSA has seen recurring similarities in pipeline accidents on construction sites. In each case, better management of the pipeline right-of-way could have prevented the accidents. Better management includes closer attention to the qualifications of individuals critical to damage prevention, better marking practices, and closer oversight of the excavation. In 2006, PHMSA issued two advisory bulletins to alert operators of the need to pay closer attention to these important damage prevention issues. The first advisory bulletin described three accidents in which either operator personnel or contractors damaged gas transmission pipelines during excavation in the rights-of-way (ADB–06–01; 71 FR 2613; Jan.17, 2006). This bulletin advised operators to pay closer attention to integrating OQ regulations into excavation activities and providing that excavation is included as a covered task under OQ programs required by subpart N. The second advisory bulletin pointed to an additional excavation accident where the excavator struck an inadequately marked gas transmission pipeline (ADB–06–003; 71 FR 67703; Nov. 22, 2006). This advisory bulletin advised pipeline operators to pay closer attention to locating and marking pipelines before excavation activities begin and pointed to several good practices as well as the best practices described by the CGA. This paragraph requires an operator electing to operate at a higher stress level to develop a plan to manage the protection of their right-of-way from excavation activities. Each operator already has a damage prevention program, under § 192.614, and a program to ensure qualification of pipeline personnel, under subpart N. This management program requires the operator to integrate activities under those programs to provide better protection for the right-of-way of the pipeline operated at the higher stress level.

E.8.5. § 192.620(d)(5)—Internal Corrosion Control

Paragraph (d)(5) adds specificity to the requirements for internal corrosion control now in pipeline safety standards for pipelines operated at higher stress levels. These internal corrosion control programs must include use of gas separators or filter separators and gas quality monitoring equipment. Operators are required to use cleaning pigs and inhibitors when corrosive gas is present. (Use of cleaning pigs and inhibitors is required when the level of one corrosive contaminant, hydrogen sulfide (H_2S), is between 0.5 and 1.0 grain per hundred cubic feet). Most operators who have applied for special permits to operate their pipeline at alternative MAOP limit H_2S to 0.5 grain. The higher levels allowed in this rule are within typical FERC tariffs, but may present an increased likelihood of internal corrosion. Maximum levels of contaminants that could promote corrosion must be reviewed quarterly, and operators must adjust their programs as needed to monitor and mitigate any deleterious gas stream constituents. PHMSA believes the levels are fully consistent with the requirements in FERC tariffs designed to prevent internal corrosion.

E.8.6. §§ 192.620(d)(6), (7), and (8)—External Corrosion Control

Since external corrosion is one of the greatest risks to the integrity of pipelines operating at higher stress levels, the special permits and this rule contain several measures to prevent it from occurring. These include use of effective external coating, addressing interference, early installation of cathodic protection, confirming the adequacy of coating and cathodic protection and diligent monitoring of cathodic protection levels. The requirements concerning quality of the coating and installation of cathodic protection for new pipelines are addressed in sections on design and construction, as discussed above. The remaining external corrosion provisions are addressed here.

Interference from overhead power lines, railroad signaling, stray currents, or other sources can interfere with the cathodic protection system and, if not properly mitigated, even accelerate the rate of external corrosion. Paragraph (d)(6) requires an operator to identify and address interference early before damage to the pipeline can occur.

Paragraph (d)(7) requires an operator to confirm both the effectiveness of the coating and the adequacy of the cathodic protection system soon after deciding on operation at higher operating stress levels/alternative MAOP. This is accomplished through indirect assessments, such as a CIS for cathodic protection and DCVG or ACVG for coating condition. After completion of the baseline internal inspection required by § 192.620(d)(9), an operator is required to integrate the results of that inspection with the indirect assessments. An operator must take remedial action to correct any inadequacies. In HCAs, an operator must periodically repeat indirect assessment to confirm that the cathodic protection system remains as functional as when first installed.

Paragraph (d)(8) requires more rigorous attention to ensure adequate levels of cathodic protection. Regulations now require an operator discovering a low reading, meaning a reduced level of protection, to act promptly to correct the deficiency. This section puts an outer limit of six months on the time for completion of the remedial action and restoration of an adequate level of cathodic protection. In addition, the operator must confirm that its actions have been effective in restoring cathodic protection.

E.8.7. §§ 192.620(d)(9) and (10)—Integrity Assessments

Among the most important ways of ensuring integrity during pipeline operations are the assessments done under the integrity management program requirements in subpart O. Paragraphs (d)(9) and (d)(10) require operators electing to operate at higher stress levels to perform both baseline and periodic assessments of the entire pipeline segment operating at the higher stress level, regardless of whether the pipeline segment is located in an HCA. The operator must use both a geometry tool and a high resolution magnetic flux tool for the entire pipeline segment. In very limited circumstances in which internal inspection is not possible because internal inspection tools cannot be accommodated, such as a short crossover segment connecting two pipelines in a right-of-way, an operator would substitute pressure testing or DA. The operator must then integrate the information provided by these assessments with testing done under previously described paragraphs. This analysis would form the basis for mitigating measures, and for prompt repairs under paragraph (d)(11).

E.8.8. § 192.620(d)(11)—Repair Criteria

The repair criteria under paragraph (d)(11) for anomalies in a pipeline segment operating at a higher stress level are slightly more conservative than for other pipelines, including pipelines covered by an integrity management program. With the tougher pipe, better coating, construction quality inspection program, coating surveys after installation and backfill, and careful attention to damage prevention and corrosion protection, a pipeline operated at higher operating stress levels should experience few anomalies needing evaluation.

E.9. § 192.620(e)—Overpressure Protection

The alternative MAOP is higher than the upper limit of the required overpressure protection under existing regulations. Paragraph (e) increases the overpressure protection limit to 104 percent of the MAOP, which is 83.2 percent of SMYS for a pipeline segment operating at the alternative MAOP in a Class 1 location.

F. Regulatory Analyses and Notices

F.1. Privacy Act Statement

Anyone may search the electronic form of all comments received for any of our dockets. You may review DOT's complete Privacy Act Statement in the **Federal Register** published on April 11, 2000 (65 FR 19477).

F.2. Executive Order 12866 and DOT Policies and Procedures

Due to magnitude of expected benefits, the DOT considers this rulemaking to be a significant regulatory action under section 3(f)(1) of Executive Order 12866 (58 FR 51735; Oct. 4, 1993). Therefore, DOT submitted it to the Office of Management and Budget for review. This rulemaking is also significant under DOT regulatory policies and procedures (44 FR 11034; Feb. 26, 1979).

PHMSA prepared a Regulatory Evaluation of the final rule. A copy is in Docket ID PHMSA–2005–23447.

PHMSA estimates that the rule will result in gas transmission pipeline operators uprating 3,500 miles of existing pipelines to an alternative MAOP. Additionally PHMSA estimates that, in the future, the rule will result in an annual additional 700 miles of new pipelines each year whose operators elect to use an alternative MAOP.

PHMSA expects the benefits of the rule to be substantial and in excess of $100 million per year. This expectation is based on quantified benefits in excess of $100 million per year (see below), coupled with un-quantified benefits associated with the rule that industry and PHMSA technical staff have identified. The expected benefits of the rule that cannot be readily quantified include:

- Reductions in incident consequences.
- Increases in pipeline capacity.
- Increases in the amount of natural gas filling the line, commonly called line pack.
- Reductions in adverse environmental impacts.

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. In the case of new pipelines, the ability to use an alternative MAOP will make it possible to transport more product per dollar of pipeline cost than would be possible without this new rule. Quantifying the value of this increased capacity is difficult, and no estimate has been developed for this analysis. For existing pipelines, operation at a higher MAOP increases the amount of gas that can be transported. PHMSA expects the value of increased capacity due to use of alternative MAOP by gas pipelines to be significant. 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.

Similarly, increases in line pack will produce increased benefits which are difficult to quantify. Line pack is increased due to gas compressibility at higher operating pressures which results in increased gas volumes in the pipeline. The reduced amount of exterior storage capacity needed resulting from increased line pack may result in capital or O&M savings for the pipelines or their customers. Greater line pack in a pipeline increases the ability of the operator to continue gas delivery during short outages such as maintenance and during peak flow periods. These benefits are not readily quantifiable.

The quantified benefits consist of:

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

Of these, pipeline fuel cost savings is the most important contributor to the estimated benefits. Although these quantified benefits do not capture the full benefits of the rule, they exceed $100 million per year.

As a consequence of the rule, PHMSA estimates that pipeline operators will realize annually recurring benefits due to fuel cost savings of $49 million that will begin in the initial year after the rule goes into effect. Additionally, PHMSA estimates that each year pipeline operators will realize one-time benefits for savings in capital expenditures 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.) The benefits of the rule over 20 years are expected to be as presented in the following table:

TABLE D.2.–1—SUMMARY AND TOTAL FOR THE ESTIMATED BENEFITS OF THE RULE

[Millons of dollars per year]

Benefit	Estimate for year 1	Estimate of new benefits occurring in each subsequent year
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 benefits evaluated over 20 years at a three percent discount rate is $1,541 million, while the present value of the benefits over 20 years at a seven percent discount rate is $1,098 million. For both discount rates, the annualized benefits would be $103.6 million.

PHMSA expects 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 HCAs.
• Preparing threat assessments.
• Patrolling pipeline rights-of-way.
• Preparing the paperwork notifying PHMSA of the decision to use an alternative MAOP.

Overall, the costs of the rule over 20 years are expected to be as presented in the following table:

TABLE D.2.–2— SUMMARY AND TOTALS FOR THE ESTIMATED COSTS OF THE RULE

Cost item	Cost by year after implementation [thousands of dollars]			
	1st	2nd—10th	11th	12th—20th
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 Assessments	$180	$30 each year	$30	$30 each year.
Patrolling	$4,620	$5,390 to $11,550	$12,320	$15,090 to $19,250.
Notifying PHMSA	Nominal	Nominal	Nominal	Nominal.
Total	$38,462	$618 each year plus patrolling costs.	$31,627	$3,733 each year plus patrolling costs.

The present value of the costs evaluated over 20 years at a three percent discount rate are approximately $239 million, while the present value of the costs over 20 years at a seven percent discount rate are approximately $165 million. The annualized costs at the three percent discount rate are approximately $16 million, while the annualized costs at the seven percent discount rate are approximately $15 million.

Since the present value of the quantified benefits ($1,541 million at three percent and $1,098 million at seven percent) exceeds the present value of the costs ($328 million at three percent and $164 million at seven percent), the rule is expected to have net benefits.

F.3. Regulatory Flexibility Act

Under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), PHMSA must consider whether rulemaking actions would have a significant economic impact on a substantial number of small entities.

The final rule affects operators of gas pipelines. Based on annual reports submitted by operators, there are approximately 1,450 gas transmission and gathering systems and an equivalent number of distribution systems potentially affected by this rule. The size distribution of these operators is unknown and must be estimated.

The affected gas transmission systems all belong to NAICS 486210, Pipeline Transportation of Natural Gas. In accordance with the size standards published by the Small Business Administration, a business with $6.5 million or less in annual revenue is considered a small business in this NAICS.

Based on August 2006 information from Dunn & Bradstreet on firms in NAICS 486210, PHMSA estimates that 33 percent of the gas transmission and gathering systems have $6.5 million or less in revenue. Thus, PHMSA estimates that 479 of the gas transmission and gathering systems affected by the rule will have $6.5 million or less in annual revenue. PHMSA does not expect that any local gas distribution companies or gathering systems will be taking advantage of the potential to use an alternative MAOP.

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. Consequently, it imposes no economic burden on the affected gas pipeline operators, large or small. Based on these facts, I certify that this rule will not have a substantial economic impact on a substantial number of small entities.

F.4. Executive Order 13175

PHMSA has analyzed this rulemaking according to Executive Order 13175, ''Consultation and Coordination with Indian Tribal Governments.'' Because the rule does not significantly or uniquely affect the communities of the Indian tribal governments, nor impose substantial direct compliance costs, the funding and consultation requirements of Executive Order 13175 do not apply.

F.5. Paperwork Reduction Act

This rule adds notification paperwork requirements and record retention on pipeline operators voluntarily choosing an alternative MAOP for their pipelines. Based on analysis of the regulation, there will be an estimated nine 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 one and one-half hours. The associated cost of these annual burden hours is $720 in year one, and $120 thereafter. No other burden hours and associated costs are expected. The Paperwork Reduction Act analysis in the docket has a more detailed explanation.

F.6. Unfunded Mandates Reform Act of 1995

This rule does not impose unfunded mandates under the Unfunded Mandates Reform Act of 1995. It does not result in costs of $132 million or more in any one year to either State, local, or tribal governments, in the aggregate, or to the private sector, and is the least burdensome alternative that achieves the objective of the rulemaking.

F.7. National Environmental Policy Act

PHMSA has analyzed the rulemaking for purposes of the National Environmental Policy Act (42 U.S.C. 4321 *et seq.*). The rulemaking will require limited physical change or other work that would disturb pipeline rights-of-way. In addition, the rule codifies the terms of special permits PHMSA has granted. Although PHMSA sought public comment on environmental impacts with respect to most requests for special permits to allow operation at pressures based on higher stress levels, no commenters addressed environmental impacts. Further, PHMSA did not receive any comment on the environmental assessment it had prepared in conjunction with the proposed rule. PHMSA has determined the rulemaking is unlikely to significantly affect the quality of the human environment. An environmental assessment document is available for review in the docket.

F.8. Executive Order 13132

PHMSA has analyzed the rulemaking according to Executive Order 13132 (64 FR 43255, Aug. 10, 1999) and concluded that no additional consultation with States, local governments or their representatives is mandated beyond the rulemaking process. The rule does not have a substantial direct effect on the States, the relationship between the national government and the States, or the distribution of power and responsibilities among the various levels of government. The rule does not impose substantial direct compliance costs on State or local governments.

Further, no consultation is needed to discuss the preemptive effect of the proposed rule. The pipeline safety law, specifically 49 U.S.C. 60104(c), prohibits State safety regulation of interstate pipelines. Under the pipeline safety law, States have the ability to augment pipeline safety requirements for intrastate pipelines PHMSA regulates, but may not approve safety requirements less stringent than those required by Federal law. And a State may regulate an intrastate pipeline facility PHMSA does not regulate. In addition, 49 U.S.C. 60120(c) provides that the Federal pipeline safety law ''does not affect the tort liability of any person.'' It is these statutory provisions, not the rule, that govern preemption of State law. Therefore, the consultation and funding requirements of Executive Order 13132 do not apply.

F.9. Executive Order 13211

This rulemaking is likely to increase the efficiency of gas transmission pipelines. A gas transmission pipeline operating at an increased MAOP will result in increased capacity, fuel savings, and flexibility in addressing supply demands. This is a positive rather than an adverse effect on the supply, distribution, and use of energy. Thus this rulemaking is not a ''significant energy action'' under Executive Order 13211. Further, the Administrator of the Office of Information and Regulatory Affairs has not identified this rule as a significant energy action.

List of Subjects in 49 CFR Part 192

Design pressure, Incorporation by reference, Maximum allowable operating pressure, and Pipeline safety.

■ For the reasons provided in the preamble, PHMSA amends 49 CFR part 192 as follows:

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 1. The authority citation for part 192 continues to read as follows:

Authority: 49 U.S.C. 5103, 60102, 60104, 60108, 60109, 60110, 60113, and 60118; and 49 CFR 1.53.

■ 2. In § 192.7, in paragraph (c)(2) amend the table of referenced material by revising item (B)(1), redesignating items (C)(6) through (C)(13) as (C)(7) through (C)(14), and adding a new item (C)(6) to read as follows:

§ 192.7 What documents are incorporated by reference partly or wholly in this part?

* * * * *

(c) * * *

(2) * * *

Source and name of referenced material	49 CFR reference
B. * * *	* * *
(1) API Specification 5L "Specification for Line Pipe," (43rd edition and errata), 2004	§§ 192.55(e); 192.112; 192.113; Item I of Appendix B.
* * * * *	* *
C. * * *	
(6) ASTM Designation: A 578/A578M–96 (Re-approved 2001) "Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications".	§§ 192.112(c)(2)(iii).
* * * * *	* *

■ 3. Add § 192.112 to subpart C to read as follows:

§ 192.112 Additional design requirements for steel pipe using alternative maximum allowable operating pressure.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure (MAOP) calculated under § 192.620, a segment must meet the following additional design requirements. Records for alternative MAOP must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this design issue:	The pipeline segment must meet these additional requirements:
(a) General standards for the steel pipe.	(1) The plate, skelp, or coil used for the pipe must be micro-alloyed, fine grain, fully killed, continuously cast steel with calcium treatment. (2) The carbon equivalents of the steel used for pipe must not exceed 0.25 percent by weight, as calculated by the Ito-Bessyo formula (Pcm formula) or 0.43 percent by weight, as calculated by the International Institute of Welding (IIW) formula. (3) The ratio of the specified outside diameter of the pipe to the specified wall thickness must be less than 100. The wall thickness or other mitigative measures must prevent denting and ovality anomalies during construction, strength testing and anticipated operational stresses. (4) The pipe must be manufactured using API Specification 5L, product specification level 2 (incorporated by reference, see § 192.7) for maximum operating pressures and minimum and maximum operating temperatures and other requirements under this section.
(b) Fracture control	(1) The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with: (i) API Specification 5L (incorporated by reference, see § 192.7); or (ii) American Society of Mechanical Engineers (ASME) B31.8 (incorporated by reference, see § 192.7); and (iii) Any correction factors needed to address pipe grades, pressures, temperatures, or gas compositions not expressly addressed in API Specification 5L, product specification level 2 or ASME B31.8 (incorporated by reference, see § 192.7). (2) Fracture control must: (i) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, gas compositions, pipe grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline; (ii) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the gas at operating parameters; (iii) Ensure at least 99 percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90 percent within five pipe lengths; and (iv) Include fracture toughness testing that is equivalent to that described in supplementary requirements SR5A, SR5B, and SR6 of API Specification 5L (incorporated by reference, see § 192.7) and ensures ductile fracture and arrest with the following exceptions: (A) The results of the Charpy impact test prescribed in SR5A must indicate at least 80 percent minimum shear area for any single test on each heat of steel; and (B) The results of the drop weight test prescribed in SR6 must indicate 80 percent average shear area with a minimum single test result of 60 percent shear area for any steel test samples. The test results must ensure a ductile fracture and arrest. (3) If it is not physically possible to achieve the pipeline toughness properties of paragraphs (b)(1) and (2) of this section, additional design features, such as mechanical or composite crack arrestors and/or heavier walled pipe of proper design and spacing, must be used to ensure fracture arrest as described in paragraph (b)(2)(iii) of this section.
(c) Plate/coil quality control	(1) There must be an internal quality management program at all mills involved in producing steel, plate, coil, skelp, and/or rolling pipe to be operated at alternative MAOP. These programs must be structured to eliminate or detect defects and inclusions affecting pipe quality. (2) A mill inspection program or internal quality management program must include (i) and either (ii) or (iii): (i) An ultrasonic test of the ends and at least 35 percent of the surface of the plate/coil or pipe to identify imperfections that impair serviceability such as laminations, cracks, and inclusions. At least 95 percent of the lengths of pipe manufactured must be tested. For all pipelines designed after [the effective date of the final rule], the test must be done in accordance with ASTM A578/A578M Level B, or API 5L Paragraph 7.8.10 (incorporated by reference, see § 192.7) or equivalent method, and either

To address this design issue:	The pipeline segment must meet these additional requirements:
	(ii) A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. Use of sulfur prints is not an equivalent method. The test must be carried out on the first or second slab of each sequence graded with an acceptance criteria of one or two on the Mannesmann scale or equivalent; or (iii) A quality assurance monitoring program implemented by the operator that includes audits of: (a) all steelmaking and casting facilities, (b) quality control plans and manufacturing procedure specifications, (c) equipment maintenance and records of conformance, (d) applicable casting superheat and speeds, and (e) centerline segregation monitoring records to ensure mitigation of centerline segregation during the continuous casting process.
(d) Seam quality control	(1) There must be a quality assurance program for pipe seam welds to assure tensile strength provided in API Specification 5L (incorporated by reference, see § 192.7) for appropriate grades. (2) There must be a hardness test, using Vickers (Hv10) hardness test method or equivalent test method, to assure a maximum hardness of 280 Vickers of the following: (i) A cross section of the weld seam of one pipe from each heat plus one pipe from each welding line per day; and (ii) For each sample cross section, a minimum of 13 readings (three for each heat affected zone, three in the weld metal, and two in each section of pipe base metal). (3) All of the seams must be ultrasonically tested after cold expansion and mill hydrostatic testing.
(e) Mill hydrostatic test	(1) All pipe to be used in a new pipeline segment must be hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 95 percent SMYS for 10 seconds. The test pressure may include a combination of internal test pressure and the allowance for end loading stresses imposed by the pipe mill hydrostatic testing equipment as allowed by API Specification 5L, Appendix K (incorporated by reference, see § 192.7). (2) Pipe in operation prior to November 17, 2008, must have been hydrostatically tested at the mill at a test pressure corresponding to a hoop stress of 90 percent SMYS for 10 seconds.
(f) Coating	(1) The pipe must be protected against external corrosion by a non-shielding coating. (2) Coating on pipe used for trenchless installation must be non-shielding and resist abrasions and other damage possible during installation. (3) A quality assurance inspection and testing program for the coating must cover the surface quality of the bare pipe, surface cleanliness and chlorides, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, coating thickness, holiday detection, and repair.
(g) Fittings and flanges	(1) There must be certification records of flanges, factory induction bends and factory weld ells. Certification must address material properties such as chemistry, minimum yield strength and minimum wall thickness to meet design conditions. (2) If the carbon equivalents of flanges, bends and ells are greater than 0.42 percent by weight, the qualified welding procedures must include a pre-heat procedure. (3) Valves, flanges and fittings must be rated based upon the required specification rating class for the alternative MAOP.
(h) Compressor stations	(1) A compressor station must be designed to limit the temperature of the nearest downstream segment operating at alternative MAOP to a maximum of 120 degrees Fahrenheit (49 degrees Celsius) or the higher temperature allowed in paragraph (h)(2) of this section unless a long-term coating integrity monitoring program is implemented in accordance with paragraph (h)(3) of this section. (2) If research, testing and field monitoring tests demonstrate that the coating type being used will withstand a higher temperature in long-term operations, the compressor station may be designed to limit downstream piping to that higher temperature. Test results and acceptance criteria addressing coating adhesion, cathodic disbondment, and coating condition must be provided to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operating above 120 degrees Fahrenheit (49 degrees Celsius). 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. (3) Pipeline segments operating at alternative MAOP may operate at temperatures above 120 degrees Fahrenheit (49 degrees Celsius) if the operator implements a long-term coating integrity monitoring program. The monitoring program must include examinations using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or an equivalent method of monitoring coating integrity. An operator must specify the periodicity at which these examinations occur and criteria for repairing identified indications. An operator must submit its long-term coating integrity monitoring program to each PHMSA pipeline safety regional office in which the pipeline is located for review before the pipeline segments may be operated at temperatures in excess of 120 degrees Fahrenheit (49 degrees Celsius). 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.

■ 4. Add § 192.328 to subpart G to read as follows:

§ 192.328 Additional construction requirements for steel pipe using alternative maximum allowable operating pressure.

For a new or existing pipeline segment to be eligible for operation at the alternative maximum allowable operating pressure calculated under § 192.620, a segment must meet the following additional construction requirements. Records must be maintained, for the useful life of the pipeline, demonstrating compliance with these requirements:

To address this construction issue:	The pipeline segment must meet this additional construction requirement:
(a) Quality assurance	(1) The construction of the pipeline segment must be done under a quality assurance plan addressing pipe inspection, hauling and stringing, field bending, welding, non-destructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing. (2) The quality assurance plan for applying and testing field applied coating to girth welds must be: (i) Equivalent to that required under § 192.112(f)(3) for pipe; and (ii) Performed by an individual with the knowledge, skills, and ability to assure effective coating application.
(b) Girth welds	(1) All girth welds on a new pipeline segment must be non-destructively examined in accordance with § 192.243(b) and (c).
(c) Depth of cover	(1) Notwithstanding any lesser depth of cover otherwise allowed in § 192.327, there must be at least 36 inches (914 millimeters) of cover or equivalent means to protect the pipeline from outside force damage. (2) In areas where deep tilling or other activities could threaten the pipeline, the top of the pipeline must be installed at least one foot below the deepest expected penetration of the soil.
(d) Initial strength testing	(1) The pipeline segment must not have experienced failures indicative of systemic material defects during strength testing, including initial hydrostatic testing. A root cause analysis, including metallurgical examination of the failed pipe, must be performed for any failure experienced to verify that it is not indicative of a systemic concern. The results of this root cause analysis must be reported 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.
(e) Interference currents	(1) For a new pipeline segment, the construction must address the impacts of induced alternating current from parallel electric transmission lines and other known sources of potential interference with corrosion control.

■ 5. Amend § 192.611 by revising paragraph (a)(1) and (a)(3)(i) and (ii) and adding new paragraph (a)(3)(iii) to read as follows:

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

(a) * * *

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

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

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

* * * * *

(3) * * *

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

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

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

* * * * *

■ 6. Amend § 192.619 by revising paragraph (a) introductory text and by adding paragraph (d) to read as follows:

§ 192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

* * * * *

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in § 192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under § 192.620(a).

■ 7. Add § 192.620 to subpart L to read as follows:

§ 192.620 Alternative maximum allowable operating pressure for certain steel pipelines.

(a) *How does an operator calculate the alternative maximum allowable operating pressure?* An operator calculates the alternative maximum allowable operating pressure by using different factors in the same formulas used for calculating maximum allowable operating pressure under § 192.619(a) as follows:

(1) In determining the alternative design pressure under § 192.105, use a design factor determined in accordance with § 192.111(b), (c), or (d) or, if none of these paragraphs apply, in accordance with the following table:

Class location	Alternative design factor (F)
1	0.80
2	0.67
3	0.56

(i) For facilities installed prior to November 17, 2008, for which § 192.111(b), (c), or (d) apply, use the following design factors as alternatives for the factors specified in those paragraphs: § 192.111(b)—0.67 or less; 192.111(c) and (d)—0.56 or less.

(ii) [Reserved]

(2) The alternative maximum allowable operating pressure is the lower of the following:

(i) The design pressure of the weakest element in the pipeline segment, determined under subparts C and D of this part.

(ii) The pressure obtained by dividing the pressure to which the pipeline segment was tested after construction by a factor determined in the following table:

Class location	Alternative test factor
1	1.25
2	[1] 1.50
3	1.50

[1] For Class 2 alternative maximum allowable operating pressure segments installed prior to November 17, 2008, the alternative test factor is 1.25.

(b) *When may an operator use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section?* An operator may use an alternative maximum allowable operating pressure calculated under paragraph (a) of this section if the following conditions are met:

(1) The pipeline segment is in a Class 1, 2, or 3 location;

(2) The pipeline segment is constructed of steel pipe meeting the additional design requirements in § 192.112;

(3) A supervisory control and data acquisition system provides remote monitoring and control of the pipeline segment. The control provided must include monitoring of pressures and flows, monitoring compressor start-ups and shut-downs, and remote closure of valves;

(4) The pipeline segment meets the additional construction requirements described in § 192.328;

(5) The pipeline segment does not contain any mechanical couplings used in place of girth welds;

(6) If a pipeline segment has been previously operated, the segment has not experienced any failure during normal operations indicative of a systemic fault in material as determined by a root cause analysis, including metallurgical examination of the failed pipe. The results of this root cause analysis must be reported to each PHMSA pipeline safety regional office where the pipeline is in service at least 60 days prior to operation 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; and

(7) At least 95 percent of girth welds on a segment that was constructed prior to November 17, 2008, must have been non-destructively examined in accordance with § 192.243(b) and (c).

(c) *What is an operator electing to use the alternative maximum allowable operating pressure required to do?* If an operator elects to use the alternative maximum allowable operating pressure calculated under paragraph (a) of this section for a pipeline segment, the operator must do each of the following:

(1) Notify each PHMSA pipeline safety regional office where the pipeline is in service of its election with respect to a segment at least 180 days before operating at the alternative maximum allowable operating pressure. 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.

(2) Certify, by signature of a senior executive officer of the company, as follows:

(i) The pipeline segment meets the conditions described in paragraph (b) of this section; and

(ii) The operating and maintenance procedures include the additional operating and maintenance requirements of paragraph (d) of this section; and

(iii) The review and any needed program upgrade of the damage prevention program required by paragraph (d)(4)(v) of this section has been completed.

(3) Send a copy of the certification required by paragraph (c)(2) of this section to each PHMSA pipeline safety regional office where the pipeline is in service 30 days prior to operating at the alternative MAOP. An operator must also send a copy to 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.

(4) For each pipeline segment, do one of the following:

(i) Perform a strength test as described in § 192.505 at a test pressure calculated under paragraph (a) of this section or

(ii) For a pipeline segment in existence prior to November 17, 2008, certify, under paragraph (c)(2) of this section, that the strength test performed under § 192.505 was conducted at a test pressure calculated under paragraph (a) of this section, or conduct a new strength test in accordance with paragraph (c)(4)(i) of this section.

(5) Comply with the additional operation and maintenance requirements described in paragraph (d) of this section.

(6) If the performance of a construction task associated with implementing alternative MAOP can affect the integrity of the pipeline segment, treat that task as a ''covered task'', notwithstanding the definition in § 192.801(b) and implement the requirements of subpart N as appropriate.

(7) Maintain, for the useful life of the pipeline, records demonstrating compliance with paragraphs (b), (c)(6), and (d) of this section.

(8) A Class 1 and Class 2 pipeline location can be upgraded one class due to class changes per § 192.611(a)(3)(i). All class location changes from Class 1 to Class 2 and from Class 2 to Class 3 must have all anomalies evaluated and remediated per: The ''original pipeline class grade'' § 192.620(d)(11) anomaly repair requirements; and all anomalies with a wall loss equal to or greater than 40 percent must be excavated and remediated. Pipelines in Class 4 may not operate at an alternative MAOP.

(d) *What additional operation and maintenance requirements apply to operation at the alternative maximum allowable operating pressure?* In addition to compliance with other applicable safety standards in this part, if an operator establishes a maximum allowable operating pressure for a pipeline segment under paragraph (a) of this section, an operator must comply with the additional operation and maintenance requirements as follows:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
(1) Identifying and evaluating threats.	Develop a threat matrix consistent with § 192.917 to do the following: (i) Identify and compare the increased risk of operating the pipeline at the increased stress level under this section with conventional operation; and (ii) Describe and implement procedures used to mitigate the risk.
(2) Notifying the public	(i) Recalculate the potential impact circle as defined in § 192.903 to reflect use of the alternative maximum operating pressure calculated under paragraph (a) of this section and pipeline operating conditions; and (ii) In implementing the public education program required under § 192.616, perform the following:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	(A) Include persons occupying property within 220 yards of the centerline and within the potential impact circle within the targeted audience; and (B) Include information about the integrity management activities performed under this section within the message provided to the audience.
(3) Responding to an emergency in an area defined as a high consequence area in § 192.903.	(i) Ensure that the identification of high consequence areas reflects the larger potential impact circle recalculated under paragraph (d)(1)(i) of this section. (ii) If personnel response time to mainline valves on either side of the high consequence area exceeds one hour (under normal driving conditions and speed limits) from the time the event is identified in the control room, provide remote valve control through a supervisory control and data acquisition (SCADA) system, other leak detection system, or an alternative method of control. (iii) Remote valve control must include the ability to close and monitor the valve position (open or closed), and monitor pressure upstream and downstream. (iv) A line break valve control system using differential pressure, rate of pressure drop or other widely-accepted method is an acceptable alternative to remote valve control.
(4) Protecting the right-of-way	(i) Patrol the right-of-way at intervals not exceeding 45 days, but at least 12 times each calendar year, to inspect for excavation activities, ground movement, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline. (ii) Develop and implement a plan to monitor for and mitigate occurrences of unstable soil and ground movement. (iii) If observed conditions indicate the possible loss of cover, perform a depth of cover study and replace cover as necessary to restore the depth of cover or apply alternative means to provide protection equivalent to the originally-required depth of cover. (iv) Use line-of-sight line markers satisfying the requirements of § 192.707(d) except in agricultural areas, large water crossings or swamp, steep terrain, or where prohibited by Federal Energy Regulatory Commission orders, permits, or local law. (v) Review the damage prevention program under § 192.614(a) in light of national consensus practices, to ensure the program provides adequate protection of the right-of-way. Identify the standards or practices considered in the review, and meet or exceed those standards or practices by incorporating appropriate changes into the program. (vi) Develop and implement a right-of-way management plan to protect the pipeline segment from damage due to excavation activities.
(5) Controlling internal corrosion	(i) Develop and implement a program to monitor for and mitigate the presence of, deleterious gas stream constituents. (ii) At points where gas with potentially deleterious contaminants enters the pipeline, use filter separators or separators and gas quality monitoring equipment. (iii) Use gas quality monitoring equipment that includes a moisture analyzer, chromatograph, and periodic hydrogen sulfide sampling. (iv) Use cleaning pigs and inhibitors, and sample accumulated liquids when corrosive gas is present. (v) Address deleterious gas stream constituents as follows: (A) Limit carbon dioxide to 3 percent by volume; (B) Allow no free water and otherwise limit water to seven pounds per million cubic feet of gas; and (C) Limit hydrogen sulfide to 1.0 grain per hundred cubic feet (16 ppm) of gas, where the hydrogen sulfide is greater than 0.5 grain per hundred cubic feet (8 ppm) of gas, implement a pigging and inhibitor injection program to address deleterious gas stream constituents, including follow-up sampling and quality testing of liquids at receipt points. (vi) Review the program at least quarterly based on the gas stream experience and implement adjustments to monitor for, and mitigate the presence of, deleterious gas stream constituents.
(6) Controlling interference that can impact external corrosion.	(i) Prior to operating an existing pipeline segment at an alternate maximum allowable operating pressure calculated under this section, or within six months after placing a new pipeline segment in service at an alternate maximum allowable operating pressure calculated under this section, address any interference currents on the pipeline segment. (ii) To address interference currents, perform the following: (A) Conduct an interference survey to detect the presence and level of any electrical current that could impact external corrosion where interference is suspected; (B) Analyze the results of the survey; and (C) Take any remedial action needed within 6 months after completing the survey to protect the pipeline segment from deleterious current.
(7) Confirming external corrosion control through indirect assessment.	(i) Within six months after placing the cathodic protection of a new pipeline segment in operation, or within six months after certifying a segment under § 192.620(c)(1) of an existing pipeline segment under this section, assess the adequacy of the cathodic protection through an indirect method such as close-interval survey, and the integrity of the coating using direct current voltage gradient (DCVG) or alternating current voltage gradient (ACVG). (ii) Remediate any construction damaged coating with a voltage drop classified as moderate or severe (IR drop greater than 35% for DCVG or 50 dBμv for ACVG) under section 4 of NACE RP–0502–2002 (incorporated by reference, see § 192.7). (iii) Within six months after completing the baseline internal inspection required under paragraph (8) of this section, integrate the results of the indirect assessment required under paragraph (6)(i) of this section with the results of the baseline internal inspection and take any needed remedial actions. (iv) For all pipeline segments in high consequence areas, perform periodic assessments as follows:

To address increased risk of a maximum allowable operating pressure based on higher stress levels in the following areas:	Take the following additional step:
	(A) Conduct periodic close interval surveys with current interrupted to confirm voltage drops in association with periodic assessments under subpart O of this part. (B) Locate pipe-to-soil test stations at half-mile intervals within each high consequence area ensuring at least one station is within each high consequence area, if practicable. (C) Integrate the results with those of the baseline and periodic assessments for integrity done under paragraphs (d)(8) and (d)(9) of this section.
(8) Controlling external corrosion through cathodic protection.	(i) If an annual test station reading indicates cathodic protection below the level of protection required in subpart I of this part, complete remedial action within six months of the failed reading or notify each PHMSA pipeline safety regional office where the pipeline is in service demonstrating that the integrity of the pipeline is not compromised if the repair takes longer than 6 months. 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; and (ii) After remedial action to address a failed reading, confirm restoration of adequate corrosion control by a close interval survey on either side of the affected test station to the next test station. (iii) If the pipeline segment has been in operation, the cathodic protection system on the pipeline segment must have been operational within 12 months of the completion of construction.
(9) Conducting a baseline assessment of integrity.	(i) Except as provided in paragraph (d)(8)(iii) of this section, for a new pipeline segment operating at the new alternative maximum allowable operating pressure, perform a baseline internal inspection of the entire pipeline segment as follows: (A) Assess using a geometry tool after the initial hydrostatic test and backfill and within six months after placing the new pipeline segment in service; and (B) Assess using a high resolution magnetic flux tool within three years after placing the new pipeline segment in service at the alternative maximum allowable operating pressure. (ii) Except as provided in paragraph (d)(8)(iii) of this section, for an existing pipeline segment, perform a baseline internal assessment using a geometry tool and a high resolution magnetic flux tool before, but within two years prior to, raising pressure to the alternative maximum allowable operating pressure as allowed under this section. (iii) If headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a pipeline segment operating at alternative maximum allowable operating pressure cannot accommodate a geometry tool and a high resolution magnetic flux tool, use direct assessment (per § 192.925, § 192.927 and/or § 192.929) or pressure testing (per subpart J of this part) to assess that portion.
(10) Conducting periodic assessments of integrity.	(i) Determine a frequency for subsequent periodic integrity assessments as if all the alternative maximum allowable operating pressure pipeline segments were covered by subpart O of this part and (ii) Conduct periodic internal inspections using a high resolution magnetic flux tool on the frequency determined under paragraph (d)(9)(i) of this section, or (iii) Use direct assessment (per § 192.925, § 192.927 and/or § 192.929) or pressure testing (per subpart J of this part) for periodic assessment of a portion of a segment to the extent permitted for a baseline assessment under paragraph (d)(8)(iii) of this section.
(11) Making repairs	(i) Perform the following when evaluating an anomaly: (A) Use the most conservative calculation for determining remaining strength or an alternative validated calculation based on pipe diameter, wall thickness, grade, operating pressure, operating stress level, and operating temperature: and (B) Take into account the tolerances of the tools used for the inspection. (ii) Repair a defect immediately if any of the following apply: (A) The defect is a dent discovered during the baseline assessment for integrity under paragraph (d)(8) of this section and the defect meets the criteria for immediate repair in § 192.309(b). (B) The defect meets the criteria for immediate repair in § 192.933(d). (C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure. (D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.4 times the alternative maximum allowable operating pressure. (iii) If paragraph (d)(10)(ii) of this section does not require immediate repair, repair a defect within one year if any of the following apply: (A) The defect meets the criteria for repair within one year in § 192.933(d). (B) The alternative maximum allowable operating pressure was based on a design factor of 0.80 under paragraph (a) of this section and the failure pressure is less than 1.25 times the alternative maximum allowable operating pressure. (C) The alternative maximum allowable operating pressure was based on a design factor of 0.67 under paragraph (a) of this section and the failure pressure is less than 1.50 times the alternative maximum allowable operating pressure. (D) The alternative maximum allowable operating pressure was based on a design factor of 0.56 under paragraph (a) of this section and the failure pressure is less than or equal to 1.80 times the alternative maximum allowable operating pressure. (iv) Evaluate any defect not required to be repaired under paragraph (d)(10)(ii) or (iii) of this section to determine its growth rate, set the maximum interval for repair or re-inspection, and repair or re-inspect within that interval.

(e) *Is there any change in overpressure protection associated with operating at the alternative maximum allowable operating pressure?* Notwithstanding the required capacity of pressure relieving and limiting stations otherwise required by § 192.201, if an operator establishes a maximum allowable operating pressure for a pipeline segment in accordance with paragraph (a) of this section, an operator must:

(1) Provide overpressure protection that limits mainline pressure to a maximum of 104 percent of the maximum allowable operating pressure; and

(2) Develop and follow a procedure for establishing and maintaining accurate set points for the supervisory control and data acquisition system.

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Carl T. Johnson,

Administrator.

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