UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines	)))	Docket No. RIN 1010-AD11 Docket ID PHMSA-2005-23447; Notice 2

COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Pursuant to the Notice of Proposed Rulemaking ("Proposed Rule") issued by the U.S. Department of Transportation ("DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA") on March 11, 2008, and published in the March 12, 2008 issue of the *Federal Register*, 73 Fed. Reg. 13167 (Mar. 12, 2008), the Interstate Natural Gas Association of America ("INGAA") submits the following comments.

EXECUTUVE SUMMARY

The proposed regulations establish eligibility standards enabling certain natural gas transmission pipelines to operate at an increased maximum allowable operating pressure ("MAOP").

INGAA is a non-profit trade association that represents the interstate natural gas pipeline industry. INGAA's members are subject to comprehensive safety regulation by PHMSA, including any regulations permitting increases in MAOP. INGAA members have been working with PHMSA on MAOP eligibility criteria for over three years, and the interest of INGAA's members in the Proposed Rule is self-evident.

INGAA appreciates that PHMSA has decided to promulgate a rulemaking on this subject. This ability to take into account the technology and process changes that have occurred since the original pipeline safety regulations were adopted in 1970 is very important. Many improvements have been made to consensus standards and specifications over these intervening decades. Adopting many of these revised standards, procedures and practices and allowing an increase in design factor will assist the United States in maintaining a competitive position in the world economy, lower the impact of siting pipelines to the public and environment and transport natural gas more efficiently.

INGAA supports the rulemaking in concept and direction and has suggested changes. INGAA requests PHMSA modify its proposed regulations as specified in the specific, section-by-section comments provided above. INGAA's changes are based on the combination of research, technical information residing in consensus standards, common operating practices within its membership and lessons learned in the Special Permitting process. Each of these recommendations addresses the technical efficacy of an issue and the cost benefit of the solution.

In light of the facts and arguments presented above, INGAA asks PHMSA to accord "grandfather" status to all previously issued Special Permits, and to allow all pending applications to proceed on their own merits, without exposing currently permitted projects or pending applications to the standards that emerge from this rulemaking proceeding.

HISTORY OF DESIGN FACTORS AND SPECIAL PERMITS ADDRESSING THESE FACTORS

Design factors have been part of the pipeline engineering standards since their inception. In many cases, these factors were used to account for imprecise engineering practice and properties, limited inspection technology and difficult maintenance processes. Improved information, technologies and practices have minimized the safety benefit of these design factors over the years. Standards organizations and other international groups and countries initiated efforts in the 1970s to examine these legacy factors and have refined and updated them.

PHMSA's pipeline safety regulations were developed in 1968 from the American Society of Mechanical Engineers (ASME) B31.8 natural gas pipeline standard which was authored in 1935. The design factors for natural gas pipelines have not been adjusted since the regulations were adopted in 1970. Over the years, the pipeline industry has had discussions with PHMSA about the desire to raise the design factor of pipelines. These discussions have ranged from recent research findings to detailed development of the Integrity Management regulations. These discussions have all lead to an increased confidence that the present design factors are conservative for today's technology, practices and procedures.

As a result, individual companies, through the Special Permit process have been working with PHMSA to set reasonable requirements for individual pipeline projects under a Special Permit process. Many of these pipeline projects under the Special Permit process have particular geographic and business characteristics resulting in a suite of particular issues and custom solutions for each given application.

INGAA identified in the beginning that this Special Permit process may be adopted on a more wide scale basis and started working with PHMSA over 3 years ago in developing a set of criteria primarily based on consensus standards. Emphasis on consensus standards was determined to be the best path since those standards are vetted through a rigorous process and there was wide acceptance and adoption of those practices among industry participants.

GENERAL COMMENTS: GRANDFATHERING

Several pipeline operators have been granted Special Permits to operate at higher design factor. INGAA is concerned that these granted Special Permits will be revoked or modified upon passage of this regulation and the requirements developed in this docket will be imposed in their place. Other operators have Special Permit applications pending before PHMSA, and INGAA is concerned that these applications will be required to adopt the provisions developed in this rulemaking, rather than their currently recognized counterparts.

The Special Permit process is a rigorous process to address the particular issues, on a particular pipeline, and INGAA is unaware of any new issues being identified during this rulemaking process that would cause those Special Permits to be revisited. Therefore, we think that the issues identified during the establishment of the individual Special Permits addresses the issues all raised in the Proposed Rule. These pipeline projects were developed and relied upon the stipulations of the Special Permits that were granted. Presently, PHMSA has the ability to revoke these Special Permits, utilizing due process, if they determine there is a pipeline safety issue. *See generally*, *Pipeline Safety: Administrative Procedures, Address Updates, and Technical Amendments*, Docket No. PHMSA-2007-0033 (INGAA letter comment April 28, 2008)(noting the need for due process in the context of Special Permit modification, suspension or revocation).

INGAA sees no need to revisit Special Permits in place or reanalyze pending Special Permit applications as a result of this Proposed Rule. All Special Permits granted to date should be grandfathered as a part of this final rulemaking, and all pending Special Permit applications should be considered using prevailing standards rather than the standards that will emerge from this rulemaking.

GENERAL COMMENTS: STANDARDS FOR ASSESSING THE PROPOSED REGULATIONS

PHMSA has a goal to be a balanced overseer for pipeline safety, and provide data driven, practicable regulations that provide a good cost/benefit justification. Some of these proposed new requirements lack a technical basis, a documented increase in overall safety performance or a positive cost/benefit justification. Also, some of the proposed requirements in this NOPR seem to conflict with, ignore or greatly exceed the requirements and criteria set forth in PHMSA's Part 192 Subpart O regulations, the referenced ASME B31.8S standard and other consensus engineering standards.

INGAA's recommendations are designed to improve the goals of the regulation by maintaining public safety goals, adjusting for technical knowledge, improving the practicality and cost/ benefit of implementing the regulations, and providing clarity.

INGAA comments are based on the following goals

- Each solution identified should have a stated purpose and add value to the overall goal of the rulemaking
- Each solution should have a technical basis or a consensus behind the change
- Each solution should be consistent with present regulations or consensus standards
- Each solution should address the overall cost benefit question..

The term of higher stress level has been used frequently throughout of the proposed rule. While it might be applicable to the cases of pressure uprating of existing pipelines, it is not applicable to other cases. The maximum operating stress is limited by, among other factors, the design factor and the SMYS (or grade) of the pipe material and high design factor does not necessarily lead to high operating stress. For an example, a X65 pipe designed with 0.8 design factor would have lower operating stress than a X80 pipe design with 0.72 design factor. It is suggested that the term of higher stress level should be replaced with higher design factor.

SPECIFIC COMMENTS: PROPOSED CHANGES TO PARAGRAPH 192.7 INCORPORATION BY REFERENCE

In general, INGAA supports the use of consensus standards to provide the technical foundation for any regulatory actions; particularly those developed under the provisions established by the American National Standards Institute (ANSI). Specifically, INGAA supports the incorporation of the standard, ASTM A 578/A579M-96 (re-approved 2001) "*Standard Specification for Straight-Beam Ultrasonic Examination of Plain and Clad Steel Plates for Special Applications*" for use in inspecting plate manufactured for pipe orders to be used for operation using the alternative design basis and life cycle management proposed by PHMSA.

SPECIFIC COMMENTS: PROPOSED SECTION 192.112 ADDITIONAL DESIGN REQUIRMENTS FOR STEEL PIPE USING ALTERNATIVE MAXIMUM ALLOWABLE OPERATING PRESSURE

Proposed 49 C.F.R. § 192.112(a): General Standards for Steel Pipe

INGAA recommends deleting Sections 192.112(a)(2) and 192.112(a)(3) in their entirety.

PHMSA proposes the use of a ratio of the diameter over the nominal wall thickness, referred to as D/t to address the threat of damage during construction and atypical loads and mechanical damage during operation of the pipeline. INGAA believes that while consideration of the relationship between wall thickness relative to pipe diameter is important, there is no hard and fact threshold that applies under all circumstances and there is a divergence of opinion within INGAA membership on what those levels should be for a given diameter and wall thickness combination. D/t limitations are particularly inappropriate for higher yield strength pipe. For pipe grades X-80 and above, the D/t ratios may exceed 100 to 1. Ovality and denting issues can be managed for these higher D/t pipelines, and for that matter any pipe under this regulation through the construction practices proposed by PHMSA in 192.328(a)(1), Quality Assurance (during construction), and by provisions in the existing ASME code that relate to analyses of instantaneous and sustained loads during operation (ASME B31.8, Paragraph 833.4).

With respect to carbon equivalents, the consensus standard API 5L establishes specifications for maximum carbon equivalents using the Ito-Bessyo formula (Pcm formula) for varying grades and wall thicknesses of steel pipe. PHMSA has proposed limitations that differ from those in API 5L, without technical justification. INGAA supports use of the limits as expressed in API 5L, absent any other information to justify differing limits.

Proposed 49 C.F.R. § 192.112(b): Fracture Control

INGAA recommends amending Section 192.112(b)(3) to read: "If it is not physically possible to achieve the pipeline toughness properties of paragraphs (b)(1) and (2) of this section, a crack arrest design must be developed and implemented or mechanical crack arrestors of proper design and spacing must be used to insure fracture arrest as described in (b)(2)(iii) of this section.".

In general, INGAA agrees with the approach proposed by PHMSA with respect to fracture control. It is critical that an operator's plan considers and addresses initiation, propagation and arrest under the range of operating pressures and temperatures anticipated on the pipeline. In addition, it is important that the fracture control plan addresses the potential under-conservatism of conventional Charpy toughness equations for higher strength steels (grades X70 and above) and enriched gases. A white paper "*Fracture Control*" has been developed by the Joint Industry Project on Alternative Design Basis and Life Cycle Management, and is submitted to support our comments.

INGAA agrees that the basis for arrest proposed by PHMSA is appropriate for new pipeline design. The basis selected by PHMSA in effect requires that approximately 58 percent of the pipe be "arrest" pipe if fracture control is based on self-arrest. For the design scenario where a separate crack arrest design is used, INGAA proposes that PHMSA amend the regulatory language to allow an operator to alternatively apply a crack arrest design based on an engineering analysis including an analysis of consequence.

Proposed 49 C.F.R. § 192.112(c)(2)(i): Plate and Coil Quality—Macro Etch Test

INGAA recommends amending Section 192.112(c)(2)(i) to read: "A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process. The acceptance criteria must be agreed to between the purchase and the mill.".

In general INGAA believes that the consensus standard API 5L provides the foundation for the materials specification and manufacturing of line pipe. Operators (purchasers of pipe) build upon API 5L through use of materials specification and manufacturing quality management programs. The Joint Industry Project on Alternative Design Basis and Life Cycle Management has developed a white paper "*Material Specification and Manufacturing*" (attached) that describes how line pipe metallurgical, chemical and dimensional properties are managed by a materials and manufacturing quality management program. Materials and manufacturing quality management programs draw upon international consensus-based standards in combination with mill and source-specific specifications, quality control measures used by the pipe mill and quality assurance used by the purchaser. The quality management program comprises four steps:

1. Pipe manufacturing mill qualification
2. Pipe standard, specifications and contracting agreements
3. Pipe manufacturing procedure specification review and agreement
4. Surveillance and auditing

The purchaser engages in a technical evaluation of the mill to ensure that the mill is qualified to produce pipe to the purchaser's specifications. The purchaser will establish a pipe specification knowing the requirements of the project for which the pipe is being procured. The mill and purchaser engage in the development and agreement upon a manufacturing procedure specification (MPS) that establishes the materials specification to standards and the purchaser's additional requirements and manufacturing procedures and quality control/quality assurance

(QA/QC) practices. The pipe mill knows best how to source the steel, roll and weld pipe to meet the performance parameters required by the purchaser. The MPS sets out the kinds of inspections and frequencies and how exceptions are to be dealt with. The MPS is designed to locate issues before they become problems and minimize exceptions.

Steel properties are specified by the operator in the pipe specification and the mill selects the chemical formulations that are designed to ensure the slab mill producer, skelp mill and the pipe mill achieve the desired final properties in the finished pipes. Most alloying elements must fall within compositional limits that are known to lead to the appropriate mechanical properties. Solidification control during continuous casting minimizes centerline segregation and lamination from refractory and slag entrapment.

Centerline segregation and lamination in the pipe body or pipe ends if it extends into the weld preparation generally reduces weld strength and may promote girth weld cracking. In particular, carbon, oxygen, sulfur and phosphorous in the carbon equivalents formulation are minimized controlled to promote weldability, and the controlled rolling (and accelerated cooling/strip coiling where applicable) using advanced thermo-mechanical parameters, and micro-alloying elements are used to assure the fine grain size and precipitation hardening effects which compensates for the loss of strength, due to the reduced carbon.

It is important to recognize that API 5L provides performance-based requirements to address the outcomes of centerline segregation, or failure of the source material to meet the metallurgical and dimensional properties of the operator’s pipe specification and API 5L. The operator, the pipe mill and plate mill must balance the use of quality control measures and the potential for out-of-spec pipe to be formed. This is not best achieved by the imposition of a single simple prescriptive approach unrelated to the negotiated MPS. The proposed singular approach can impact the production process of a particular mill greatly increasing the cost.

Even considering the performance-based requirements set forth in API 5L, INGAA recommends that the purchaser require specific slab mill inspections, such as macro-etch testing. Macro-etch testing is a valuable quality control method to be applied by the mill. This approach aligns with the approach proposed by PHMSA. While INGAA agrees with PHMSA in the value of the tests, the frequency and acceptance criteria are best left to be agreed upon between the purchaser and the mill, based on mill configuration, and slab source, among other factors.

Proposed 49 C.F.R. § 192.112(c)(2)(ii): Plate and Coil Quality—Ultrasonic Test

INGAA recommends amending Section 192.112(c)(2)(ii) to read: "An ultrasonic test or other equivalent method to identify lamination, cracks and inclusions. The acceptance criteria must be agreed to between the purchaser and the mill in accordance with the guidelines stated in ASTM A578.".

With respect to ultrasonic inspection of plate/coil or pipe, INGAA agrees that the pipe mill must include a comprehensive plate/coil and pipe mill inspection program to check for surface defects and inclusions that can be injurious to the integrity of the pipe. This program can be conducted on plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program using as a basis, guidelines in ASTM A578 to check for imperfections such as laminations. Alternatively, INGAA believes that the pipe mill may conduct full-body UT of the pipe. Full-body UT entails the use of a single transducer oscillating back and forth across the internal pipe surface. The basis of either approach is to assure that the inspection finds defects that exceed a certain minimum size in the body of the plate or pipe, and provides coverage for 100 percent of the pipe ends back a specified length. The work group recommends that the performance criteria set forth in ASTM 578 be used for plate inspection and as a basis for establishing criteria for full-body UT.

Proposed 49 C.F.R. § 192.112(d): Seam Quality Control—Hardness Test

INGAA recommends amending Section 192.112(d)(2) to read: "There must be a hardness test method used to ensure hardness levels established between the purchaser and the mill of the following:".

As a starting point, INGAA believes that API 5L provides the technical foundation for managing seam quality control. The pipe weld seam must meet the minimum requirements for tensile strength as specified in API 5L for the appropriate pipe grade properties. INGAA is aware of the work being undertaken by the Joint Industry Project on Alternative Design Basis and Life Cycle Management. The JIP has developed a white paper on "*Materials Specification and Manufacturing*" and is submitted as part of the INGAA comments.

INGAA agrees with PHMSA that pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam confirms adequate ductility across the plate, HAZ, and weld material volumes and must be performed on one length of pipe from each heat. INGAA does not agree with the use of a threshold value of 280 Vickers Hardness (Hv 10). While API 5L does provide such a threshold value for sour gas service, it does not provide a single, fixed value for the gas service addressed under 49 C.F.R. § 192; that is the transportation of non-corrosive gases. INGAA believes that the pipe mill and the purchaser should establish a maximum hardness in the manufacturing procedure specification and quality assurance plan.

API 5L requires that the pipe weld seam must be 100 percent UT or x-ray inspected to ensure there are no defects or cracks. In addition, API 5L requires that pipe ends be non-destructively inspected by either UT or x-ray, to identify there are injurious laminations or inclusions interacting the weld volume.

Proposed 49 C.F.R. § 192.112(e)(1): Mill Hydrostatic Test—New Segment

INGAA recommends amending Section 192.112(e)(1) to read: "A hydrostatic test of all pipe will be conducted in the pipe mill at a pressure of at least 95% of SMYS, for a duration of 10 seconds including the allowance for end loading.".

INGAA understands that the mill hydrostatic test is really a quality control test conducted on each pipe manufactured in the mill. It is an important interim quality control test but none-the-less it is a quality control test. The ultimate test of the pipe's integrity is the eight-hour pressure test, often referred to as the proof test, referred in Subpart K of part 192 conducted on the pipe as constructed in the field.

INGAA is aware of the work being undertaken by the Joint Industry Project on Alternative Design Basis and Life Cycle Management. The JIP has developed a White Paper "*Materials Specification and Manufacturing*" and is submitted as part of the INGAA comments. API 5L is in its forty-third edition and for a number of years has specified a test to 90 percent of SMYS for 10 seconds[1]. Many pipe mills have adjusted there production design and configuration to abide by this requirement. The members of the JIP work group discussed test pressure and duration and reached the following conclusions.

- Testing to 95 percent of SMYS is appropriate as long as the current provisions that allow for end-loading compensation as per Appendix K are applicable.
- The work group found that a duration in excess of 10 seconds did not add quantifiable value to the test and the increased duration could impact productivity of pipe mills.

[1] Even the Forty-Fourth edition of API 5L, effective October 1, 2008 retains the 90% SMYS for at least 10 seconds for large diameter pipe.

Proposed 49 C.F.R. § 192.112(f)(1): Coating

INGAA recommends amending Section 192.112(f)(1) to read: "The pipe must be protected against external corrosion by non-shielding, non-disbonding and non-cracking coating.".

Under the proposed regulation, pipes must be coated with "non-shielding, fusion bonded epoxy coating." Fusion bonded epoxy (FBE) coatings have proven performance in pipeline applications for over thirty years around the world. INGAA believes that it is important to allow for alternatives to ensure improved technologies are not arbitrarily restricted. Prescriptive language specifying only FBE coatings is inappropriate because it risks stifling innovation. Regulations should allow the use of manufacturer's coating based on these performance requirements. Three layer coatings especially FBE-PE and other hybrids have provided good performance in other parts of the world. Abrasion resistant coatings and other high integrity specialty coatings need inclusion through performance language such as non-disbonding, non-shielding, or non-cracking.

Proposed 49 C.F.R. § 192.112(g): Fittings and Flanges

INGAA agrees with the provisions proposed by PHMSA. But to clarify, pipe fittings, valves and flanges, associated with line pipe and main line block valves, should be designed and purchased in accordance with applicable reference standards or their equivalent, already incorporated within 49 CFR 192. The referenced standards may be supplemented by the operator's supplemental requirements to ensure the materials meet the minimum engineering design specifications.

Proposed 49 C.F.R. § 192.112(h)(2): Compressor Stations—Discharge Temperature

INGAA recommends amending Section 192.112(h) to read: "If research or testing shows that the coating will withstand a higher temperature in long-term operations, the compressor station may be designed to limit discharge temperature to that higher temperature.".

It appears that the PHMSA concerns with respect to compressor station discharge temperatures relate to the long-term durability and integrity of plant and field applied coating for operations greater than 120^{o}F. The concern arises when considering operating scenarios for uncontrolled compressor discharge temperatures projected to heat the coating to a temperature that may reach 150^{o}F or higher. These reports refer to tar, asphalt and tape based coatings that predominated prior to the use of FBE.

All newer pipelines built under PHMSA regulations must have two corrosion protection systems. The first line of defense against corrosion is the coating system. The concern arises out of historical experience in the pipeline industry when some pipeline systems were operated at temperatures above 120^{o}F, even as high as 160^{o}F. In some cases, these corrosion coatings were non conductive and prevented the cathodic current from completing the circuit. The second line of defense is the applied cathodic protection current which is applying small voltage potential between the pipe and the soil. PHMSA in 49 C.F.R. Part 192 requires a minimum test point (or close interval survey) voltage to ensure the imposed current provides sufficient protection in the event the coating has deteriorated. If the pipe was "shielded" and the applied potential could not protect the surface.

The Joint Industry Project on Alternative Design Basis and Life Cycle Management has developed the White Paper "*A Review of the Performance of Fusion-Bonded Epoxy Coatings on Pipelines at Operating Temperatures Above 120º F*" (attached). This paper is a review that summarizes operating and performance case histories, as well as laboratory and field-testing of the long-term performance of FBE coatings. This paper documents that FBE coatings have demonstrated good adhesion and little disbondment in both laboratory-testing environments and after 30 years of operation at temperatures greater than 120^{o}F on systems in the United States, Canada and the Middle East. In addition, FBE remains conductive even when disbonded as a continuous barrier like film proud of the pipe. However, FBE coatings do not block the cathodic protection current, meaning that disbondment of the coating does not interrupt the cathodic protection system, and the imposed CP current continues to protect the pipe from external corrosion and SCC.

The work summarized in the JIP white paper shows that even the first generation FBE coatings having seen as many as thirty years service have performed well at temperatures above 120^{o}F. Even so, blistering and disbondment has been observed on in-service lines in operation above 120^{o}F. Laboratory tests conducted on FBE coatings in simulated environments at temperatures above 120^{o}F do indicate a greater degree of disbondment as the temperature is increased towards 200^o F however any corrosion is minimized by the CP system.

FBE coating is known to be conductive, meaning that even when disbonded, cathodic protection remains effective. In-service experience described in this white paper confirms this behavior. FBE coatings do not shield the cathodic protection currents.

It is not apparent that additional laboratory testing on FBE coating at temperatures above 120^{o}F will add any information not already known based on the studies described in this white paper. An operator may elect to conduct additional laboratory testing.

Recognizing that there is the potential for disbondment, an operator may elect to conduct above ground surveys using close interval surveys to confirm the effectiveness of the applied potential and use direct current voltage gradient (DCVG) surveys periodically to locate holidays, if any, in the FBE coating. The conductivity of FBE coatings ensures the integrity of the second line of protection, the applied CP system, is not compromised.

SPECIFIC COMMENTS: PROPOSED SECTION 192.328 ADDITIONAL CONSTRUCTION REQUIRMENTS FOR STEEL PIPE USING ALTERNATIVE MAOP

Proposed 49 C.F.R. § 192.328(b)(2): Girth welds—Previously Constructed Segments

INGAA recommends moving Paragraph 192.328(b)(2) from Section 192.328 to Section 192.620, under 192.620(c)(3), in a manner that is similar to the requirement for pressure testing.

The proposed regulation refers to pipelines that were constructed prior to the effective date of this rule. This new requirement is being placed in the wrong area of the regulations. Paragraph 192.328 is in the construction requirement section of the regulations and is not a retroactive requirement on pipelines that are already constructed. Paragraph 192.620 is in the Operations section of the regulations and applies retroactively to all pipelines.

Proposed 49 C.F.R. § 192.328(d) – Initial Strength Testing

INGAA recommends amending Section 192.328(d) to track the language used in the Special Permits granted to date; namely, "Any pipe failure occurring during the prein-service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office.".

This item deals specifically with "any failures indicative of fault in material". Material is produced as specified in the pipeline safety regulations and the additional requirements of proposed 192.112. Even with the rigorous controls, there is a possibility that a piece of pipe will have a material defect. This unacceptable pipe will be found during the pressure test if the defect is large enough to grow to failure. If it does not grow to failure, the safety margin is sustained.

The requirement in the NPRM, which states that "the segment must not experience any failure indicative of fault in material" during the hydrotest is excessive. A root cause analysis of any test failure, however, is appropriate. If there is a systemic issue with the material more needs to be done to understand and address the issue.

In a paper by John Kiefner, "*Role of Hydrostatic Testing in Pipeline Integrity Assessment*" the technical benefits for the test are stated as follows:

> *"The purpose of hydrostatic testing a pipeline is to either eliminate any defect that might threaten its ability to sustain its maximum operating pressure or to show that none exists. A key word here is pressure. Hydrostatic testing consists of raising the pressure level above the operating pressure to see whether or not any defects with failure pressures above the operating pressure exist. If defects fail and are eliminated or if no failure occurs because no such defect exists, a safe margin of pressure above the operating pressure is demonstrated."*

This statement is the underlying philosophy for all pressure tests including the post construction test addressed in this paragraph. In the case of post construction tests, the defects that the operator is trying to find or prove do not exist are material and construction defects.

Special Permits granted to date have addressed pressure test failures by requiring a root cause failure analysis. If a systemic issue was found during the test, discussions had to be held with the regional offices. The requirement stated in typically in the Special Permits is:

> *"Assessment of Test Failures: Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office."*

Proposed 49 C.F.R. § 192.328(e) – Cathodic Protection

INGAA recommends deleting Section 192.328(d) in its entirety. If necessary, a reference to 192.455 can be added instead of restating the requirement.

This proposed regulation is unnecessary. Under 49 C.F.R. § 192.455, cathodic protection must be installed and placed in operation within one year after the completion of construction.

SPECIFIC COMMENTS: PROPOSED SECTION 192.620
ALTERNATIVE MAOP FOR CERTAIN STEEL PIPELINES

Proposed 49 C.F.R. § 192.620(a): Specification of the Alternative MAOP

INGAA recommends the following changes to Section 192.620(a):

For the new pipelines that meet all of the special provisions in the NPRM, it is recommended that:

- *Class 1 pipelines be limited to operation at 80% of SMYS and pressure tested to 1.25 times MAOP*
- *Class 2 pipelines be limited to operation at 67% of SMYS and pressure tested to 1.25 times MAOP*
- *Class 3 pipelines be limited to operation at 56% of SMYS and pressure tested to 1.5 times MAOP*
- *Uncased road and railroad crossing be limited to 67 % of SMYS in Class 1 locations and to 56% of SMYS in Class 2 locations. Actual design may be subject to permit requirements*

For the existing pipelines, it is recommended that:

- *Class 1 pipelines be limited to operation at 80% of SMYS and pressure tested to 1.25 times MAOP*
- *Class 2 pipelines be limited to operation at 67% of SMYS and pressure tested to 1.25 times MAOP*
- *Class 3 pipelines be limited to operation at 56% of SMYS and pressure tested to 1.5 times MAOP*
- *Station piping be limited to operation at 56% of SMYS and pressure tested to 1.5 times MAOP*
- *Fabricated assemblies would be limited to operation at 67% of SMY and pressure tested to 1.25 times MAOP*
- *Uncased road and railroad crossing be limited to 67 % of SMYS in Class 1 locations and to 56% of SMYS in Class 2 locations. Actual design may be subject to permit requirements*

For class location changes, it is recommended that a new paragraph be added to 192.611 to provide the following:

- *Pipe that operates at 80% and in accordance with paragraph 192.620 and changes from Class 1 to Class 2, can continue to operate up to 80% SMYS*
- *Pipe that operates at 80% and changes from Class 2 to Class 3 or from Class 1 to Class 3 would need to have the pressure lowered to 67% of SMYS or be replaced with pipe designed at 67% SMYS or less*
- *Pipe that operates at 67% and in accordance with paragraph 192.620 and changes from Class 2 to Class 3 can continue to operate at 67%*

For clarification, in the Class location table, the heading should be "Test Factor" rather than "Factor".

The requirements in the Proposed Rule are more restrictive than current regulations and previously granted Special Permits. The design factors set in the Proposed Rule do not recognize that the class location may change after the pipeline has been constructed. Special provisions are provided in the existing regulations to allow for the class location change without the need for pipe replacement, contingent on a pressure test to the next class location test factor. It is important to note that the regulations require operations and maintenance activity frequency be based on the class location. The higher the class location, the more frequent the inspection or other activity is performed. These additional provisions address the slightly higher risk due to consequence by reducing the likelihood of an event through more frequent inspection.

Waivers have been granted in the past to pipelines operating to 80% or more of SMYS that were grandfathered and have subsequently experienced a class change from Class 1 to Class 2. In order to obtain this Special Permit, companies agreed to in-line inspection of the pipeline and to employ additional preventative and mitigative measures such as those that are mandated within a company's Integrity Management Plan.

Special Permits have been granted to pipelines operating at 60% or more of SMYS in Class 3 locations where the pressure test was not to the level required by the regulations (1.5 times MAOP). Waivers have been granted to pipelines operating at 72% or more of SMYS of design pressure in Class 3 locations, where neither the design nor the pressure test met the requirements of the regulations. The companies in these cases also agreed to in-line inspection of the pipeline and operations in accordance with the companies Integrity Management Plan. The granting of these waivers was part of the agreement reached between PHMSA and the industry in 2002 as part of the promulgation of the integrity management regulations in order to help justify the extreme cost of the regulations. Many of these pipelines contain HCAs.

A white paper “*Alternative Pipeline Design Pressures*” has been developed on this topic (attached). It discusses the current regulations, the Special Permits granted for performing Integrity Management in lieu of replacing pipe and the proposed regulations.

The proposed regulations do not have a provision for compressor station, meter station, road crossings or fabricated assemblies to operate at higher pressures. As written, a compressor station in a Class 1 area can be operated at 80% of SMYS. INGAA has recommended changes for those special cases.

Proposed 49 C.F.R. § 192.620(b)(6): Disqualification for Past Failure Indicating a Fault in Material

INGAA recommends amending Section 192.620(b)(6) to read: “Any pipe failure occurring during normal operations must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office.”.

The Proposed Rule states that the segment must not experience any failures during normal operations indicative of fault in material. This proposed requirement is excessive as the failure may be a single event. If there is a failure, a root cause analysis should be conducted in order to ascertain that the failure is not indicative of a systemic materials issue. If there is a systemic issue with the material, more needs to be done to understand and address the issue.

Proposed 49 C.F.R. § 192.620(c)(3): Strength Tests

INGAA recommends that Section 192.620(c)(3) be amended to read

"For each segment, do one of the following:

(i) Perform a strength test as described in 192.505 to at least the factor stated in (a) of this section times the maximum allowable operating pressure: or

(ii) For a segment in existence prior to [the effective date of this regulation], if the pressure test levels do not meet the requirements of subparagraph (a)(2)(ii), certify, under paragraph (c)(1), that a strength test was conducted and provide an engineering critical analysis discussing the relationship of the pressure test to actual operating pressure and the affects of remaining defect size, pipe toughness, fracture control properties and fatigue on the pipeline.".

For existing pipelines, pressure test levels may not have been to the levels stated in paragraph (a) of this section; however, the tests may have been very near those levels. Some relief from this requirement should be allowed. In 192.328(b)(2) the requirement for weld NDE is somewhat reduced recognizing that every weld may have not have experienced NDE. This rationale should apply to pressure tests as well in order to gain some relief from the pressure test requirements.

This paragraph mandates the criteria for pressure testing in Class 1 areas, but is silent concerning Class 2 and 3 areas.

In a paper written for Alliance Pipeline, and contained in the docket for their waiver or Special Permit for increasing operating pressure, Kiefner and Associates concluded

> *"…there would be little additional benefit gained in terms of demonstrating that the pipeline is fit for the modest proposed increase in operating stress by repeating the hydrostatic test to the incrementally higher level necessary to meet the 1.25 factor".*

The paper states the reason for these conclusions and included that more than ¾ of all pipeline were tested to 95% of SMYS, more than ½ of all joints were tested to 97% SMYS or greater and more than 1/3 of all the joints were tested to 99% of SMYS and there was no indication of systemic quality problems. In addition, the conclusions were justified by pipe manufacturing controls, resistance to mechanical damage, the decay of pressure with distance downstream of compression, and the minimal difference in safety factor as compared to current regulations.

Proposed 49 C.F.R. § 192.620(d)(1): Threat Assessment

INGAA recommends amending Section 192.620(d)(1) to read: "The operator must include in their design, construction, material, and operations and maintenance procedures and specifications provisions for operation using a higher design pressure.".

The proposed regulation implies that operation at the higher stress levels is inherently riskier and therefore requires additional mitigation procedures. The slight increase in risk, however, is already mitigated through all of the additional design, materials, construction, and operations requirements of these proposed regulations. It is unclear what additional procedures are being discussed in this proposed requirement.

Proposed 49 C.F.R. § 192.620(d)(2): Notifying the Public

INGAA recommends: (1) changing the title of Section 192.620(d)(2) to "Assessing potential impact area" and (2) deleting Section 192.620(d)(2) in its entirety.

This item appears to require a special notification to the public near pipelines that will be operating at higher design factors. Public notification about pipelines is already required by 49 C.F.R. § 192.616, making this requirement redundant. The same conditions exist whether the pipeline is operating under this design factor or not, except there may be more of the public affected. These types of adjustments are already incorporated in 192.616.

Proposed 49 C.F.R. § 192.620(d)(3): Remote Valve Control in High Consequence Areas

INGAA recommends amending Section 192.620(d)(3)(iii) to read: "Remote valve control must include the ability to close the valve and monitor the position (open and close) of the valve.".

This item states the requirements for timing of valve closure in a high consequence area ("HCA"). INGAA is not aware of any study or research that shows that this is effective in controlling the primary consequences on natural gas transmission pipelines. The requirement seems arbitrary and is contrary to PHMSA and industry research and operational experience.

Especially onerous is the requirement for additional pressure monitoring upstream and downstream of the valve. INGAA is not aware of any benefit in additional monitoring of the pipeline pressure upstream and downstream of the valve. As was documented in the research reports mentioned above, the presence of additional pressure recording devices is counteracted by the physics of compressed gas resulting in a *de minimis* reduction in consequences. Pressure monitoring requires additional equipment and the resultant maintenance where the benefit is not known and has not been justified.

In addition, the requirement to be able to remotely open the valve is contrary to many companies' operational policies. Many operators believe that if the situation is so serious that remote closure of the valve is required, on-site personnel will make the determination that the area is safe prior to re-pressurizing the segment and therefore do not allow remote opening of the valve.

Proposed 49 C.F.R. § 192.620(d)(4)(i): Patrolling Frequency

INGAA recommends amending Section 192.620(d)(4)(i) to read: "Patrol the right of way per section 192.705 using a frequency of not more than 4 1/2 months; but at least four times each calendar year and after a known event that may affect the integrity of the pipeline.".

The patrolling frequency proposed in the NPRM is excessive. INGAA is not aware of any technical justification for the proposed frequency however it does recognize that it follows the frequency mandated for hazardous liquid pipelines.

A review of the reportable incident data for both gas and hazardous liquid transmission lines does not show any benefit from the increased patrolling frequency for hazardous liquid lines. In 2007, there were 26 incidents due to excavation damage were reported for the approximately 160,000 miles of hazardous liquid pipelines. In 2007, 14 incidents due to excavation damage were reported for the approximately 300,000 of natural gas transmission pipelines. Assuming that both types of pipelines are utilizing the same one call excavation damage prevention systems, it would appear that the rate of excavation damage was approximately three and one half times greater for hazardous liquid pipelines that have the inspection frequency of 26 times a week versus the natural gas transmission pipelines who visual inspection frequency that is considerably less.

Correspondingly, a report by CFER Technologies for PRCI shows that unless patrolling is done at least daily, there is not much chance of prevention for excavation damage. In addition, B31.8 only requires once per year in Class 1 and 2 even when Class 1 pipe can operate at 80%.

INGAA conducted a survey of its membership as to their recommendation for a visual inspection frequency and the white paper "*Survey of Effectiveness of Visual Inspections on Natural Gas Transmission Pipelines*" The consensus of the experts was that a periodic visual inspection four times a year with supplemental inspections after known events that may affect the integrity of the pipeline would provide the best overall benefit.

Proposed 49 C.F.R. § 192.620(d)(4)(ii): Soil Monitoring Plans

INGAA recommends deleting Section 192.620(d)(3)(ii) in its entirety.

As proposed, operators would have to develop formal plans to "to monitor for and mitigate occurrences of unstable soil and ground movement." Such activities are already covered in operators' damage prevention programs. Additionally, the items to be covered in the proposed soil monitoring plan are already covered in operator plans for continuing surveillance, 49 C.F.R. § 192.613, transmission line patrolling, *Id*., § 192.705, and transmission lines leakage surveys, *Id*., § 192.706 Finally, soil monitoring is addressed in an operator's manual of operations and maintenance procedures as required by 49 C.F.R § 192.605 (Procedural manual for operations, maintenance, and emergency response). An additional plan is neither needed nor justified by the related costs.

Proposed 49 C.F.R. § 192.620(d)(4)(iii): Depth of Cover

INGAA recommends (1) deleting the firsts sentence of Section 192.620(d)(4)(iii) in its entirety and (2) amending the second sentence of Section 192.620(d)(4)(iii) to read: "If observed conditions indicate the possible loss of cover in an area where damage to the pipeline may result due to the loss of cover, replace the cover or provide appropriate prevention and mitigation measures as necessary.".

The currently proposed language governing depth of cover is confusing. The first sentence says to maintain depth of cover to the requirements stated in 49 C.F.R.§ 192.327 or 49 C.F.R. § 192.328. The first sentence statement in the proposed language requiring that cover be maintained is a requirement that cannot be obtained in any practical sense. The second sentence in the Proposed Rule says that if observed conditions indicate the possible loss of cover, perform a depth of cover survey and replace cover as necessary. The second sentence is more aligned with a performance requirement that can be obtained and is event driven. All presently issued Special Permits holders are utilizing the second sentence language.

Based on studies of incidents where depth of cover was recorded, it was found that there is no correlation between depth of cover and the occurrence of excavation damage. There are situations where the removal of cover may pose a threat of damage to the pipeline due to agricultural situations. In these cases the restoration of cover may be appropriate but there may be situations where cover cannot be permanently restored. In these situations there may be more appropriate mitigative measures that can be employed, such as the addition of a barrier.

For new pipelines in favorable areas, the pipeline company may be able to provide additional cover during construction, delaying the inevitable effects of random erosion. For existing pipelines that may enter into this regime, they were most likely installed in accordance with 49 C.F.R. § 192.327, the depth of cover requirement in a Class 1 area was 30 inches. Some removal of cover may have occurred have already during the life of the pipeline due to agriculture, normal soil erosion or other factors. This paragraph, as written would require the operator to maintain cover to 30 inches for existing pipelines which may result in significant environmental disturbance to replace cover over long segments of pipeline. This requirement does not seem to be practicable.

Proposed 49 C.F.R. § 192.620(d)(4)(iv): Line of Sight Markers

While INGAA does not recommend any changes to the “line of sight” language imbedded in the NOPR, the utility and safety benefits of this requirement was questioned in the PHMSA public meeting held on March 5, 2007.

Proposed 49 C.F.R. § 192.620(d)(4)(v): Review of Damage Prevention Program

INGAA recommends amending Section 192.620(d)(4)(v) to read: "Review the best practices for damage prevention identified by the Common Ground Alliance and incorporate applicable practices into the operator's damage prevention program"

Under proposed Section 192.620(d)(4)(v), an operator would have to identify and review national consensus standards and practices as they emerge, and then "meet or exceed those standards or practices" by incorporating appropriate changes into the operator's damage prevention program. As detailed below, the vague language in the proposed regulation invites inconsistent and possibly conflicting enforcement, giving operators no clear and certain guidance on what they should do to avoid an enforcement action.

The requirement, as stated, does not identify the standards or practices to be reviewed, however the preamble indicates that the regulation is referring to best practices developed by the Common Ground Alliance ("CGA"). Proposed Rule, 73 Fed. Reg. at 13177. Even within an agreed set of best practices regulatory uncertainty can arise because an operator may chose to follow one standard or practice while inspection personnel may believe the operator should follow another. Another issue during inspections may be the determination of which items in a standard or practice should be followed by the operator. Under INGAA's recommended language, an operator would review its damage prevention program against consensus standards and practices, and employ the appropriate practices into the damage prevention program.

Proposed 49 C.F.R. § 192.620(d)(4)(vi): Right-of-Way Management Plan

INGAA recommends deleting Section 192.620(d)(3)(vi) in its entirety.

The requirement to develop and implement a right-of-way plan is duplicative of an operator's damage prevention program and other requirements in the present regulations. This additional program is not necessary or justified. The intent as stated is to protect the segment from damage due to excavation damage and this requirement is the same as required in a operator's damage prevention programs as stated in 49 C.F.R. § 192.614(a), which provides that "each operator of a buried pipeline must carry out, in accordance with this section, a written program to prevent damage to that pipeline from excavation damage."

The other conditions proposed as part of this rule are already covered in 49 C.F.R. § 192.613 "Continuing Surveillance", *Id.*, § 192.705 "Transmission Lines: Patrolling" and Id. § 192.706 "Transmission Lines: Leakage Surveys". These items are addressed in an operator's manual of operations and maintenance procedures as required by 49 C.F.R. § 192.605 "Procedural Manual for Operations, Maintenance, and Emergency Response".

Proposed 49 C.F.R. § 192.620(d)(5): Controlling Internal Corrosion

INGAA recommends (1) amending Section 192.620(d)(5)(i) to read: "Develop and implement a program to monitor gas quality to prevent internal corrosion and to remediate any gas quality excursions where internal corrosion may result." and (2) deleting Sections 192.620(d)(5)(ii)-(v) in their entirety.

This proposed regulation is somewhat duplicative, yet in conflict with the new regulation at 49 C.F.R. § 192.476 "Internal Corrosion Control: Design and Construction of Transmission Line". The new regulation provides specific requirements for new pipelines for the control of internal corrosion and. also has a provision for "change to existing transmission line" which would apply to any pipeline that is presently in operation and would be up-rated based on the Proposed Rule. With conflicting requirements, the operator may not be able to meet both requirements.

This proposed regulation also sets specific limits on gas quality. These limits may be in conflict with gas quality guidelines approved by the Federal Energy Regulatory Commission in an operator's pipeline tariff. In addition, there is no justification in the Proposed Rule for the limits set.

The proposed regulation requires the use of cleaning pigs and inhibitors and sampling of accumulated liquids. This requirement is required regardless of the gas quality, whether or not there is liquid water and whether or not there are other prevention and mitigation options available to the operator. The language used in 49 C.F.R. § 192.476 is better stated and covers all the same issues without the need to mandate work that may not be needed.

In response to the new regulations at 49 C.F.R. § 192.476, INGAA developed guidelines in order to assist pipeline operators in determining the requirements of this regulation. These guidelines "*Internal Corrosion Control: Design and Construction of Transmission Line*" are attached. In addition, a White Paper, "*Management of Time Dependent Threats*" has been developed (attached) which discusses the concerns and remediation of gas quality issues.

Proposed 49 C.F.R. § 192.620(d)(7)(i): External Corrosion Control through Indirect Assessment: Period for Conducting Initial Assessment

INGAA recommends amending Section 192.620(d)(7)(i) to read: "Within one year of placing the cathodic protection of a new segment in operations or within one year after recalculating the maximum allowable operating pressure of an existing segment under this section, perform a close-interval survey to determine the adequacy of the cathodic protection system.".

The proposed regulation therefore implies that direct assessment must be conducted on the pipeline after construction and installation of the cathodic protection systems. These requirements together are excessive and not necessary. These requirements are in addition to a pressure test and in-line inspection with a magnetic flux leakage tool. This means that the pipeline must be assessed using all three tools identified in Subpart O of the pipeline safety regulations.

The close interval survey may be appropriate in order to confirm that the cathodic protection system is operating as designed. CIS is not performed in winter months in cold climates and the time between completion of construction in the fall and CIS in the summer will exceed six months.

Proposed 49 C.F.R. § 192.620(d)(7)(ii): Remediation of Coating Damaged During Construction

INGAA recommends amending Section 192.620(d)(7)(i) to read: "Remediate the coating or insure cathodic protection levels are appropriate to mitigate corrosion.".

The Proposed Rule requires operators to "assess the integrity of the coating and adequacy of the cathodic protection through an indirect method such as close-interval survey, direct current voltage gradient or alternating current voltage gradient". Close-interval surveys are used to confirm the adequacy of cathodic protection. Voltage gradient surveys are used to determine coating defects. Neither tool can meet both requirements. This implies that two separate surveys are required.

This proposed requirement also states that remediation of the coating must be performed based on NACE RP-0502 for any indication that is severe or moderate. This requirement is in conflict with the NACE standard which determines severe or moderate based on two or more above ground methods, not one.

The coating survey is not necessary; any coating anomaly is protected from corrosion by the cathodic protection system.

A White Paper "*Management of Time Dependent Threats*" has been developed (attached) and discusses the requirements and needs for corrosion control activities.

Proposed 49 C.F.R. § 192.620(d)(7)(iii): External Corrosion Control through Indirect Assessment: Integration of Indirect Assessment with Baseline Internal Inspection

INGAA recommends amending the first clause of Section 192.620(d)(7)(iii) to read: "Within one year after completing the baseline internal inspection required under paragraph (9) of this section . . . ."

This proposed requirement states that results of the above ground assessment results must be integrated with the results of in line inspection (“ILI”) within 6 months of performing the ILI. This timing is burdensome and not necessary. The value of this quick data integration is not explained or technically justified.

Proposed 49 C.F.R. § 192.620(d)(7)(iv)(B): External Corrosion Control through Indirect Assessment: Placement of Pipe-to-Soil Test Stations

INGAA recommends that this item should be moved to 192.328(e) and that it could be clearer if it stated that “no location in an HCA can be further than one mile from a cathodic protection test station.”.

This proposed regulation would require installation of 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.” As an initial matter, this item does not seem to fit under the topic of periodic assessments. This item may better fit under 192.328(e) as a construction requirement.

More importantly, the proposed regulation is impractical under certain circumstances. For example, assume a pipeline running through a farm field comes within 600 feet of a church. The church makes it an HCA, but it is not practical to place the test station in the HCA since that would involve placing the test station in the farm field.

Proposed 49 C.F.R. § 192.620(d)(7)(iv)(C): Integration with Baseline and Periodic Assessments

INGAA recommends deleting Section 192.620(d)(7)(iv) in its entirety once clause (d)(7)(iv)(B) is moved to 49 C.F.R. § 192.328(e).

This proposed requirement states that there must be periodic close interval surveys of the pipelines in HCAs and that they are performed in association with subpart O. This statement is not clear. Subpart O addresses integrity management and allows the use of one of three assessment techniques. Proposed Section 192.620(d)(10) requires periodic in-line inspections at a frequency determined by the operator. This item implies that CIS is required at different intervals than the ILI interval. The need for close interval surveys is not justified or explained in the Proposed Rule.

Proposed 49 C.F.R. § 192.620(d)(8)(i): External Corrosion Control through Cathodic Protection: Remediation Deadline

INGAA recommends amending Section 192.620(d)(8)(i) to read: "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 one year of the failed reading; and".

This item states requirements for what is required if a test point reading falls below criteria. Since the test stations are required in or near HCAs and are rather closely spaced with specific requirements on what do if the readings fall below criteria, the need for CIS is not justified.

This proposed requirement states that remediation must be completed within 6-months. This requirement is excessive and not technically justified. Based on the seasonal issues and associated land use issues, as well as the time it takes to obtain permits, a one-year timeframe is more appropriate.

Proposed 49 C.F.R. § 192.620(d)(8)(ii): External Corrosion Control through Cathodic Protection: Close Interval Surveys to Confirm Restoration of Cathodic Protection

INGAA recommends amending Section 192.620(d)(8)(ii) to read: "After remedial action to address the loss of CP, the operator must confirm that the remedial action did restore the cathodic protection system to criteria as identified in 192 subpart I.".

This item requires a CIS after remediation for a CP issue. This requirement is excessive and not justified. The reason for a failed reading may not require CIS to confirm restoration of CP. Examples include loss of power, a cable cut, a short, etc. all of which can be fixed and have no bearing on the effectiveness of the CP on the segment. The operator does need to confirm that the remedial action was appropriate and effective, however CIS is not always necessary or may be inappropriate.

Proposed 49 C.F.R. § 192.620(d)(9)(iii): Baseline Integrity Assessment: Direct Assessment of "Non-Piggable" Segments

INGAA recommends amending Section 192.620(d)(8)(ii) to read: "If headers, mainline valve by-passes, compressor station piping, meter station piping, or other short portion of a segment cannot accommodate a geometry tool and a high resolution magnetic flux tool, use either direct assessment or pressure testing to assess that segment or develop and implement a corrosion control plan to address corrosion of the segment.".

This item requires the use of direct assessment ("DA") for segments that are not piggable. These segments may be designed per 49 C.F.R. § 192.111, and therefore would not be required to follow the requirements of 49 C.F.R. § 192.620. In addition, DA may not be appropriate for periodic assessments at these locations. Previous waivers have allowed operators to develop a corrosion control plan that does not require DA but is entirely appropriate for the subject segments. Pressure testing is also an alternative to DA where ILI cannot be performed and should be considered as an option as well.

Proposed 49 C.F.R. § 192.620(d)(11): Making repairs:

INGAA recommends amending Section 192.620(d)(11) to read as follows:

(i) Do the following when evaluating an anomaly:
(A) Use a method for determining remaining strength of a corroded pipeline that is appropriate for the pipe being evaluated
(B) Take into account the tolerance of the tools used for the assessment

(ii) Repair a defect immediately if any of the following apply:
(A) For new pipelines, a dent discovered during the baseline assessment under (d)(9) of this section and the defect meets the criteria in 192.309(b). For existing pipelines, a dent discovered during the baseline assessment under (d)(9) of this section and the defect meets the criteria in 192.933(d).
(B) The defect meets the criteria for immediate repair condition in 192.933(d)(1)(iii)
(C) A corrosion defect with a predicted failure pressure to MAOP ratio of 1.1 or less.

(iii) If paragraph (d)(ii) of this section does not require an immediate repair, repair a defect within one year of any of the following:
(A) The defect meets the criteria for a one-year condition in 192.933(d)(2)
(B) A corrosion defect with a predicted failure pressure to MAOP ratio of 1.25 or less.

Item 11(i) requires the use of the most conservative calculation for determining the remaining strength of the pipe. This statement seems to imply that more than one calculation must be performed. Each calculation method has various advantages and disadvantages given the situation, and provides conservative results if correctly supplied. This requirement is excessive and has not been technically justified.

The idea of ILI tool tolerance is addressed in the inspection protocols used by PHMSA for inspection of an operator's integrity management program. If Subpart O is referenced in lieu of this proposed requirement, there is no need for this requirement.

Item 11(ii) in general, proposes that immediate repair conditions must be replaced based on the criteria set forth. These proposed requirements are extremely conservative and in many cases are not achievable. These criteria are not consistent with Subpart O requirements and have not been technically justified.

These issues have been addressed in a White Paper "*Safety Factors for Assessing Pipeline Anomalies*" (attached) which states that the requirements outlined in ASME B31.8S and incorporated into Subpart O of part 192 are appropriate for pipelines operating up to 80% of SMYS.

Item 11(ii)(A) sets dent criteria to that required for the constructing of new pipelines, even if the pipeline is already in operation. For existing pipelines, this is not a readily achievable requirement and is not technically justified. The requirements under 49 C.F.R. § 192.933(d) are the appropriate criteria to apply to existing pipelines

Item 11(iii), in general, proposes that one year repair conditions must be replaced based on the criteria set forth. These proposed requirements are extremely conservative and in many cases are not achievable. These criteria are not consistent with Subpart O requirements and have not been technically justified.

Again, these issues have been addressed in the White Paper "*Safety Factors for Assessing Pipeline Anomalies*".

Early Special Permits that were granted early in the program required that any anomaly with a predicted failure pressure to MAOP ratio of 1.1 or less should be an immediate repair condition. A one year repair timeframe was an anomaly with a predicted failure pressure to MAOP ratio of 1.25 or less. Later, Special Permits tightened these already conservative requirements by adding wall loss factors such that an immediate repair condition also included any wall loss of 60% or more. Conversely, a one year condition included any wall loss of 40% or more. These additional factors are not technically justified and add much more conservatism than is necessary.

Item 11(iv) is not clear. The terminology is not consistent with Subpart O requirements in the regulations or ASME B31.8S. If an indication from an ILI or DA does not require an examination or evaluation, it is not determined to be a defect. Based on the ILI assessment information, the indications not remediated are classified and used to determine the next integrity assessment. This paragraph seems to repeat the requirements of 10(i) of this paragraph, yet the terminology or intent seems to conflict. Paragraph 10(i) is the appropriate language to use to require subsequent inspections and references Subpart O where the requirements are more clearly stated.

INGAA would prefer that paragraph 192.620(d)(11) as written be deleted in its entirety and replaced with the statement "examination, evaluation and remediation of any indication or anomaly must be in accordance with Subpart O of this part". However, it is important that the appropriate repair criteria be utilized for pipelines operating at the higher pressure levels.

SPECIFIC COMMENTS: PREAMBLE

The preamble has a few errors that INGAA wishes to point out so that the final rule will be correct. In addition, comments on some questions posed in the preamble are provided. These changes and comments are as follows:

B.1 The phrase "but not to exceed 80% of SMYS" at the end of paragraph one is incorrect. There is no upper limit to the pressure under which a grandfathered pipeline can operate.

B.6 Paragraph one, the review of existing permits, may be an appropriate action for PHMSA to take. PHMSA should not use this review to impose additional requirements on those operators which Special Permits nor revoke any Special Permits already granted.

B.6 Paragraph two, PHMSA should continue to expeditiously process any Special Permits they receive regardless of the status of this Proposed Rulemaking. The operators who have submitted the Special Permits may need to increase pressure to meet customer demand before the rulemaking is complete. Additionally, operators may need relief from both existing regulations and the proposed regulations as drafted.

C.3 Paragraph two makes reference to "level 2 of API Specification 5L". The new edition of this specification will likely be published before this rulemaking is complete. The reference, as stated will be outdated. PHMSA should review the proposed new edition of this specification and make appropriate references as part of the final rule.

C.3 Paragraph eight requires certification of serviceability for fittings and other components. It is not known what this requirement means. PHMSA should clarify this requirement; does PHMSA mean that mill certificates are required for each component?

C.4 Paragraph four states that "industry practice has been to non-destructively test only a sample of girth welds". INGAA takes exception to this statement. Although this represents the regulatory requirement, industry practice for INGAA member companies is to non-destructively test nearly all girth welds.

C.4 Paragraph six states that "since the initial strength test is a destructive test, it only detects flaws relatively close to failure during operation. This could leave in place smaller flaws that could grow more rapidly at higher stress levels." INGAAA takes exception to this statement. The pressure test eliminates all flaws that may fail significantly above operating pressure and to the level of the strength test (1.25 times MAOP or greater). Any flaws left in place will not grow more rapidly at higher stress levels and there is nothing that will cause them to grow. PHSMA should review research on pressure testing to more accurately state the how flaws are manifested and grow and how pressure testing minimizes the material and construction threats.

C.7.4 Paragraph two states that “More frequent patrols of the right-or-way prevent damage by giving the operator more accurate and timely information bout potential sources of ground disturbance and other outside forces”. This statement is not supported by research or statistics. In fact, research and statistics found that patrolling at greater frequencies provided no benefit in the prevention of damage.

C.7.7 Paragraph one implies that geometry tools are run for baseline purposes and during periodic assessments. This is an incorrect statement based on the proposed regulations. Geometry tools are required for the baseline assessment but not for periodic assessments. The language in the Proposed Rule is correct.

C.7.8 Paragraph one states that “The higher stress levels of operation can allow more rapid growth of materials”. This statement is incorrect. The growth of anomalies is not dependent on operating stress level.

D.2 Paragraph 4 has a statement that is incorrect. “In the case of new pipelines, the ability to use an alternative MAOP will make it possible to transport more product”. This statement may be true for existing pipelines but new pipelines are designed for the required capacity as certificated regardless of operating stress level.

CONCLUSION

In light of the facts and arguments presented above, INGAA requests PHMSA to accord “grandfather” status to all previously issued Special Permits, and to allow all pending applications to proceed on their own merits, without exposing currently permitted projects or pending applications to the standards that emerge from this rulemaking proceeding. INGAA further requests PHMSA modify its proposed regulations as specified in the specific, section-by-section comments provided above.

Respectfully submitted,

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