Increasing MAOP on U.S. Gas Transmission Pipelines

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by
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“Clear Knowledge in the Over Information Age”

This report is developed from information clearly and readily in the public domain.
Executive Summary

This report presents an independent review of recent discussions to increase the maximum allowable operating pressure (“MAOP”) on certain U.S. gas transmission pipelines. These changes would be accomplished by permitting a higher maximum stress level (as a percent of SMYS) for various class locations by increasing the maximum design factor from the current 0.72 to 0.8, and/or allowing higher design factors in class locations, waiving traditional pressure testing requirements usually mandated for class location changes. A higher design factor allows the pipeline operator to increase pressures, improving gas pipeline efficiency, via a combination of opportunities to: raise the capacity of the pipeline, reduce the capital cost of new pipelines (i.e., less steel and welding costs from thinner, higher strength pipe), and/or reduce the operating cost because of higher gas density flow and associated reduced friction loss. These changes must be approved by PHMSA via a pipeline specific waiver made through a public notification process. Recently, three pipelines have applied for waivers to increase MAOP pressures.

Accufacts believes pressure increase should be permitted by the waiver process on certain specific pipelines or pipeline segments that can properly demonstrate that critical process elements (some would call them stages) related to a pipeline’s lifecycle have occurred, are in place, well documented, and effective (see lifecycle textbox). This burden of proof is on the pipeline operator, not PHMSA, to demonstrate that the lifecycle elements are thorough and complete. In addition, through the waiver process, PHMSA can and may set additional requirements, such as requiring smart pigging on all high stress pipeline, and/or mandating improvements in third party damage prevention programs as a condition of a specific waiver. All waivers should include the requirement that waivers may be revoked should PHMSA determine conditions authorizing the waiver are found to have not been met during the long lifecycle of the pipeline.

While this paper focuses primarily on gas, a brief discussion is also presented as to why increasing pressures on liquid pipelines may not be as viable or economically advantageous, and as a result should be much more limited. Observations obtained from PHMSA’s 3/21/06 MAOP public meeting are summarized and additional key issues and concerns are also identified that need to be considered/addressed before granting pressure increase waivers.

3 These pipelines are the Maritimes and Northeast Pipeline, Alliance Pipeline, and the Rockies Express Pipeline, whose respective public waiver notices may be found at:
   http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/pdf/06-2829.pdf
   http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/pdf/06-2830.pdf
   http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/pdf/06-2831.pdf

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The Lifecycle Approach for Pipelines

This author is often asked if the lifecycle approach means that pipelines have a limited life. The answer to that is yes, but a properly managed steel pipeline has a life expectancy of well over a hundred years, if not significantly longer. A pipeline not properly managed, or treated recklessly, has a considerably shorter life span (sometimes months before its first rupture failure), even if the pipeline is constructed with new modern techniques. It is very important to not lose sight of the point that there is no such animal as an invincible steel pipeline!

PHMSA Class Waiver Threshold Requirements

- No pipe segments changing to Class 4 locations will be considered.
- No bare pipe will be considered.
- No pipe containing wrinkle bends will be considered.
- No pipe segments operating above 72% SMYS for a class 3 waiver.
- Records must be produced that show a hydrostatic test to at least 1.25 x MAOP.
- In-line inspection must have been performed with no significant anomalies identified that indicate systemic problems.
- Up to 25 miles of pipe on either side of the waiver location must be included in the pipeline company’s Integrity Management program and periodically inspected with an in-line inspection technique.

In issuing the June 29, 2004 public notice for class location change waivers, PHMSA listed a set of threshold requirements, along with an extensive chart identifying three levels of acceptance criteria: probable, possible, and requires substantial justification. Given their importance, the threshold requirements are listed above for quick reference. The full ten page “Criteria for Class Location Change Waivers” can be found at the public docket reference.4

Accufacts must caution that given the large economic incentives behind gas pipeline pressure increases, it can become very tempting to overstate the effectiveness of certain elements in a pipeline lifecycle to gain an approval. Attempts to rush approval using incomplete engineering analysis or poor risk assessment techniques to fill critical information gaps needed to make proper decisions about waiver requests must be avoided. Special precautions must insure that all elements in a pipeline’s lifecycle are satisfactory. This approach provides multiple levels of independent safety protection to assure pipeline containment. Over-reliance on just one element, such as integrity management (“IM”) in a maintenance program, or serious gaps in critical lifecycle information, substantially reduce prudent checks and balances, increase risks of failure by many orders of magnitude, and negate the intent of performance based safety approaches. For those waiver requests where serious information gaps may exist (e.g., “requires substantial justification”), a very high-pressure hydrotest, well in excess of minimum federal limits (e.g., minimum test pressures of 100% SMYS), in combination with other management practices may be the only mechanism to overcome critical lifecycle information deficiencies for a waiver.

For example, pipeline risks can be greatly increased because of poor construction techniques that may be missed as a result of the serious lack in current regulatory construction inspection

4 Ibid., OPS Notice Docket No. RSPA-04-17401.

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associated with gaps between FERC and PHMSA pipeline oversight. The author has observed that FERC, a pipeline siting/permit agency, rarely inspects during construction activities (having neither the safety responsibility, experience, manpower, nor background), and PHMSA (or its interstate agents), the organizations chartered with federal pipeline safety oversight in the U.S., but not pipeline siting, don’t take jurisdiction until the pipeline has been placed in service (i.e., pressured). This inspection gap can create situations that substantially increase the potential for time dependent anomalies to be introduced into a pipeline during construction. In all fairness, more responsible U.S. pipeline operators, even though they are not obligated, take extra quality precautions that can be easily demonstrated to avoid introduction of such anomalies from poor construction activities. Unfortunately, too many other operators only comply with the minimal requirements that don’t adequately address this serious exposure.

Why the Increase in Gas Transmission Pipeline Pressures?

While population is certainly growing, it is actually the shift to decentralized gas fired power plants that is driving most of the growing gas demand in this country. Nevertheless, a sound, safe, and efficient pipeline infrastructure is very important to the wellbeing of the country. Given the considerable transmission infrastructure already in place (approximately 300,000 miles of gas transmission pipelines in the U.S.), old and new gas pipeline operators are under considerable financial pressure to get the greatest efficiency on this critical and expensive infrastructure. It is not unusual for large gas pipeline projects to cost many hundreds of millions of dollars up to several billions of dollars. Adding to the complexity of the critical infrastructure debate are problems associated with expanding or even developing new pipeline right-of-ways in many segments of the country where open space can be at a premium. Ask landowners how they feel about the increasing use of eminent domain in right-of-way proceedings that are not always applied wisely.

All hydrocarbon streams moved in pipelines are compressible. Compressible means that the volume of the material changes as a function of pressure and is usually stated as the inverse of the bulk modulus \((C= -1/\text{BM})\). Gases are highly compressible and follow well-defined thermodynamic principles relating density, the mass per unit volume, to temperature and pressure. Liquid hydrocarbon streams are much less compressible than gases but these liquids, are nevertheless, also compressible. Because liquid hydrocarbons are usually much more complex mixtures of many hydrocarbon compounds, the bulk modulus is typically stated as a range for liquid products such as gasoline, jet fuel, diesel or crude oil. As a point of general reference, at most gas transmission pipeline pressures, gas is approximately 100 to 150 times more compressible than hydrocarbon liquids, and these liquids are about 100 times more compressible than steel.

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5 See minutes of Washington State Citizens Committee on Pipeline Safety Meeting of March 16, 2006.
6 The proposed Alaska natural gas pipeline, because of its capacity, operating environment and length, is somewhat unique in its size for a pipeline capital investment (currently estimated at approximately $20 billion).
7 The bulk modulus ("BM"), a thermodynamic property, is the pressure required to change the volume of the material by a certain fraction when pressure is exerted on the substance. The negative sign means that as the pressure increases the volume shrinks.
8 For example, the bulk modulus for gasoline at 60 °F is between 125,000 and 150,000 psi.
Because of the high compressibility in gas pipelines, as the pressure is increased the system pressure loss associated with flow is reduced along the pipeline because the actual gas velocity, the velocity calculated at the actual pressures and temperature within the pipe, is reduced.\(^9\) Thus for a fixed mass flow, the efficiency of moving gas along a pipeline is increased (less system pressure loss) as the pipeline pressure is raised. There is normally a limit to pressure increases as other factors take control. For example, depending on gas composition, liquid can “fall out” or separate out of the gas at higher pressures causing multiphase flows that can induce slug force loading stresses on pipelines and other operating complications.

In addition, since the inception of the design factor/area classification approach almost sixty years ago to insure a certain safety margin for a gas pipeline to hold pressure, a greater understanding and many technical advances have been made in all elements of a pipeline lifecycle. Given the high potential to increase gas pipeline efficiencies while maintaining proper levels of safety, we believe pressures can be increased on certain gas transmission pipelines subject to the conditions mentioned earlier. Such waiver pressure increases should not be granted lightly or across all pipelines, even new pipelines, if critical information is missing, technological capabilities overstated, or risk assessment approaches misapplied.\(^10\)

**Brief Observations on Increasing Liquid Pipeline Pressures**

While the proposed pressure increase applies only to gas transmission pipelines, a brief discussion on liquid pipelines is warranted to help explain why such an increase is unwarranted for most liquid systems. In U.S. pipeline regulation, the class location/design factor approach is not utilized and most liquid pipelines operate under a single maximum design factor of 0.72 throughout their system, with a permitted 10% overpressure accumulation that could take a liquid pipeline to 79% SMYS (1.10 X .72). As mentioned earlier, hydrocarbon liquids are approximately 100 to 150 times less compressible than gas in transmission pipelines. As a result, capacity or throughput on a liquid pipeline system can only be improved by increasing the actual liquid velocity. Unlike gases, where increasing the pressure can reduce actual velocity, on a liquid pipeline velocity is directly related to the capacity increase, as density will not change significantly for the liquid because of the much lower compressibility.\(^11\) As one increases the actual velocity on a pipeline, the system pressure drop increases by a power of two and the horsepower requirements by a power of three. Thus for a liquid system doubling the capacity doubles the velocity, increases system pressure drop by four (\(2^2\)) and horsepower requirements by a factor of eight (\(2^3\)). Ironically, because of the compressibility, even though it is reduced, high velocities introduce other risks such as that from surge (a very rapid pressure change associated with velocity, velocity changes, the BM, and fluid mass).

Many liquid pipeline systems are faced with demands to increase or push throughput on their existing systems while they are at the upper end of the velocity spectrum. There is no standard limiting the velocity within a liquid pipeline. There are some guidelines and many companies also

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\(^9\) This should not be confused with the capacity of a gas pipeline that is stated as the flow at standard referenced conditions (a temperature of 60º F and 14.7 psia, or MMSCF).

\(^10\) Risk assessment should never be applied where misinformation or critical information “gaps” create high uncertainty.

\(^11\) There are limited applications to utilize DRA (Drag Reducing Agent) in liquid pipelines to “cheat” the energy equation, but the economic benefit/application of DRA is highly limited.
have their own design limits which can vary considerably among companies. As velocities increase, a management team must incorporate other design system considerations to insure that the system can’t lose pressure control from surge. These considerations are usually required well before so called “erosion velocity ” limits take over. The greater the velocity (i.e., capacity) the more significant the “system” design complexities or safeties needed to avoid overpressure situations that can break through the pipeline's hydraulic profile (also known as breaking profile). It is this combination of reduced compressibility, actual velocity, increased system pressure loss, marked horsepower requirements, and surge exposure that usually drives the economic decision to new pipeline (or looped parallel pipeline) rather than maximum operating pressure increase to meet additional capacity requirements for most existing liquid pipelines. The economic benefits of liquid pipelines are thus limited to raising the pressures in systems that can accept rational higher velocity, which is usually on larger diameter pipelines operating at the lower end of the velocity spectrum. Thus a very limited number of older pipelines can realize savings via delaying additional pump station capital costs by increasing maximum design pressures. For new liquid pipelines there would be savings in pipe metal from thinner pipe.

**Focusing on U.S. Gas Transmission Pipelines**

For a given pipe diameter, thickness, and grade, which are usually fixed, MAOP is determined by the design factor (the higher the design factor the greater the permitted pressure). Table 1 represents the current design factor limitations as defined by U.S. federal pipeline regulation (49CFR912.11-Design Factor (F) for steel pipe), and a breakdown by class location for the approximate 300,000 miles of U.S gas transmission pipelines. These percentage/mileage numbers will vary slightly depending on the reporting database, but the distribution is in the right ballpark. In the U.S., class location is driven mainly by building density. The higher the class location number the greater the building density, and thus the assumption of greater potential for higher population around a pipeline. The U.S pipeline regulations do not set pipeline offset “safety” or buffer distances to buildings or major gathering centers as is required in some other countries.

<table>
<thead>
<tr>
<th>Class Location</th>
<th>Design Factor</th>
<th>% of Total Mileage</th>
<th>Miles of Pipeline</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.72</td>
<td>90</td>
<td>270,000</td>
</tr>
<tr>
<td>2</td>
<td>0.6</td>
<td>5</td>
<td>15,000</td>
</tr>
<tr>
<td>3</td>
<td>0.5</td>
<td>&lt;5</td>
<td>&lt;15,000</td>
</tr>
<tr>
<td>4</td>
<td>0.4</td>
<td>~0.5</td>
<td>~1,500</td>
</tr>
</tbody>
</table>

For the vast majority of U.S. gas transmission pipelines (the lower density class location 1), a MAOP has historically been determined to be 72% of SMYS (design factor of 0.72). There are exceptions to this limitation such as the approximately 5,000 miles, of class 1 gas transmission pipelines grandfathered to operate at higher stress levels than 0.72 SMYS prior to enactment of federal pipeline regulation. It is also worth noting that, of the above 300,000 miles of pipeline, approximately 7% (20,000 miles) are required to be inspected under the new gas integrity regulations defining high consequence areas (“HCAs”). To date, approximately 33% of the gas

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12 The hydraulic profile is the maximum operating pressure permitted on a liquid pipeline and mirrors the elevation profile, based on a hydrotest and the gravity of the liquid being moved.
transmission pipelines within HCAs have been inspected. To be fair, when including additional pipeline inspected not in HCAs, the total inspected pipeline under IM increases to 17%, or approximately 50,000 miles.\footnote{Jeryl L. Mohn, “Testimony on Behalf of INGAA Before the Subcommittee on Highways, Transit and Pipelines Committee on Transportation and Infrastructure U.S. House of Representatives,” March 16, 2006.}

While MAOP is defined in regulation, not all parties understand that gas transmission pipeline regulation permits pressure “accumulations” up to 110 percent MAOP or 75% SMYS which ever is lower (49CFR192.201(a)(i)). In the case of increasing MAOP to 80% SMYS, a 10% increase would put peak possible pressures at 88% SMYS, a little to close to the 90% SMYS hydrotest limit. It is not clear what accumulation pressure, if any, will be allowed for pipelines requesting a 0.8 design factor. For a specific waiver, this accumulation decision should depend on the minimum stress level (minimum hydrotest/MAOP ratio) and timing of the most recent hydrotest. Experience has clearly indicated that minimum hydrotest pressures should be 1.25 times the MAOP.

Modern pipe steel, that follows exacting manufacturing quality control and testing, and incorporates rigorous welding techniques, can withstand pressures well in excess of those contemplated for pressure increase without bursting. These modern steel pipelines include anomalies but these anomalies may not be a risk of concern, even during the long life of a pipeline. To ensure that pipelines do not initially contain anomalies that can become an early operating problem, a hydrotest is required before a pipeline can become operational. For gas transmission pipelines, U.S. pipeline regulations require a hydrotest to be performed to at least 125 percent of MAOP. This means that a hydrotest in excess of 90% SMYS may not have been carried out. Many operators perform hydrotests well above 90% SMYS to reduce the size of possible time dependent anomalies (the greater the hydrotest pressure the smaller the remaining anomalies in the pipe). IM regulations also call for periodic inspection/testing of gas transmission pipelines in HCAs, though hydrotesting is only one option for re-inspection.

U.S pipeline regulations specify no limit on the upper value of a hydrotest (though there is an inherent pipeline specific value known to more knowledgeable pipeline operators). Some countries, such as Canada, have historically placed a rational upper limit on a hydrotest as the first confirmed deviation in the pressure-volume curve. The purpose of a high hydrotest pressure test is to remove or decrease the size of anomalies that remain by taking larger threat anomalies to failure. The major problem facing pipelines is how to avoid or spot those specific anomalies that can survive a hydrotest or other inspection methods that can grow to failure with time, or are added after the last appropriate integrity inspection that can grow to failure between inspections at the higher operating pressures. Examples of anomalies that can grow over time include: 1) the obvious corrosion related (either external or internal, or stress corrosion cracking, or SCC), 2) pressure cycling sensitive such as seam weld associated with older pipelines (not a problem with modern pipe) and wrinkle bends (usually reflective of poor construction techniques), and anomalies added from third party damage that don’t fail immediately, which is a greater problem with modern pipe.
tougher pipe (i.e., horizontal directional drill, or HDD). Thus the fundamental question when considering whether to raise pressures on a gas pipeline distills down to determining the confidence that all time dependent anomalies that could fail at the higher pressures have been removed or don’t exist. Anomalies of concern include those stable anomalies that could be activated into the time dependent category as a result of an operating pressure increase on an already operating pipeline.

Smart pigging has proven to be a superior technology at identifying general corrosion anomalies in pipelines, especially certain anomalies that can be exacerbated or introduced after a hydrotest. Unfortunately, to date smart pigging cannot reliably determine stress corrosion cracking in most gas pipelines. The good news is that for new pipelines, SCC risk can be virtually eliminated by proper use of modern coatings such as FBE, prudent construction techniques, and environmental studies looking for SCC risk environments. Manufacturing anomalies that might go from stable to time dependent can usually be screened out as a risk of concern by proper construction/welding record documentation and or proper inspection methods. The last major time dependent risk of concern is that associated with third party damage that is latent (didn’t fail at the time of the damage). Given newer and tougher pipe, this latent anomaly cannot and should not be removed as a bona fide risk of concern during pressure increases.

The current state of smart pigging technology, such as magnetic flux leakage, is currently not reliable at determining those third party damage introduced risks, such as latent grooves, that can fail as pressures are increased. Thus, in the absence of a fairly recent high pressure hydrotest, other methods must be called upon to thoroughly evaluate whether third party time dependent risks are present in a pipeline segment sufficient to disallow a pressure waiver. These other factors could be: 1) the state of the damage prevention program, whether it is effective, and how assertive the pipeline operator is maintaining the program, 2) the history and nature of third party damage on the pipeline segment, 3) the condition as well as width of the pipeline right-of-way, and 4) the depth of the pipeline (deeper is usually better). As mentioned earlier, one of the more insidious time dependent third party threat activities that Accufacts has observed all too often relates to HDD activities. It should be noted that this author does not condone recent highly publicized attempts to sterilize wide swaths of pipeline right-of-way in a deceptive attempt to improve pipeline safety. We believe such efforts are overkill and very misguided, suggestive of poor management processes or practices.

General Observations on the 3/21/06 MAOP Public Meeting

As mentioned earlier, PHMSA held a public meeting in Washington, DC on March 21, 2006 to discuss the MAOP increase on gas transmission pipelines. Slide presentations and transcripts of the meeting can be found at:

http://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=40&s=3C926B4D78B845F1ADCE449D3A2F8EEA&c=1

Several focused observations from this meeting should prove helpful. Table 2 represents a summary of the approximate gas transmission mileage as well as the permitted maximum design

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14 HDD is an especially insidious third party threat given the bore tool’s propensity to easily weaken pipe and the expanding use of HDD that may or may not be under the control of the pipeline operator.
factors, and the approximate miles of pipeline currently operating above 0.72% SMYS for several countries derived from a combination of various presentations at the meeting.

Table 2 Approximate Gas Transmission Mileage, Maximum Regulatory Design Factor, and Mileage Operating over 0.72% SMYS

<table>
<thead>
<tr>
<th>Country</th>
<th>Approx. Transmission Mileage</th>
<th>Maximum Design Factor</th>
<th>Approx. Mileage Now Operating &gt;0.72</th>
</tr>
</thead>
<tbody>
<tr>
<td>USA</td>
<td>300,000</td>
<td>0.72</td>
<td>5,000</td>
</tr>
<tr>
<td>Canada</td>
<td>156,000</td>
<td>0.80</td>
<td>14,000</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>13,000</td>
<td>0.80</td>
<td>1000</td>
</tr>
<tr>
<td>Japan</td>
<td>2,000</td>
<td>0.40</td>
<td>--</td>
</tr>
</tbody>
</table>

As can be seen, the U.S. has substantially more gas transmission pipeline miles than the countries shown. The increase to a maximum design factor of 0.8 spans several decades in Canada and is a more recent development in the United Kingdom. One needs to be careful that comparisons among countries are appropriate and not taken out of context. For example, Canada has a superior right-of-way “Pipeline Crossing Regulation” program that has proven to be highly successful in reducing third party damage to transmission pipelines in the approximate eighteen years it has been in place.15 The United Kingdom has proximity distance requirements defining clearances between pipelines and dwellings as well as defining areas where transmission pipelines are not permitted. The U.S. has neither of these programs and probably could not propagate such regulation given its extensive existing pipeline network and its different jurisprudence. Ironically, third party damage threats and safety offset differences should play a significant role, as discussed earlier, in decisions to raise pressures on a pipeline through waivers here in the U.S.

For modern steel pipelines, stress is not the primary overriding issue. Within reason, it is how the operator manages the threats to the pipeline through the stages of its lifecycle. It should be noted that assuming no threat is present, such as presupposing a low corrosion rate that is unproven, is not managing the threats and represents very poor risk management! Ignoring the consequences of a possible rupture in a highly populated area is also indicative of bad management practices, and risk assessment should never be utilized to compensate for or justify poor pipeline route selection.

Important presentations that played a major consideration in confirming this author’s opinion to permit pressure increases were those showing the lifecycle approaches related to the approximately 5000 miles of grandfathered gas pipeline operating above 0.72 here in the U.S.16 The long and successful history of these pipeline is a result of superior high pressure hydrotesting (well above 100% SMYS completed many decades ago), and a litany of management processes throughout the pipelines’ lifecycle demonstrating that the operators have placed proper focus on avoiding and controlling time dependent anomalies that could fail.

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Key Issues and Concerns Regarding the Granting of Pressure Waivers

In determining that a lifecycle approach is appropriate for certain modern pipelines, we have clearly indicated that no serious information gaps regarding time dependent anomalies (more than just corrosion) be present. One of the most serious misuses of risk assessment principles is to misapply this technique to fill in critical information gaps or to miss or make misleading assumptions or misrepresentations about certain threats that can actually lead the pipeline system to rupture failure. If a pipeline requesting a pressure waiver does not have the documentation to properly address these issues, such as careful construction techniques, the waiver should not be granted. Given the incredible economic benefits that can be realized for gas transmission pipelines, care must be exercised to assure that poor risk assessment does not replace sound engineering approaches and prudent judgment regarding safety. We must caution that suggestions that modern pipelines are invincible are usually perceived as sure signs of serious management deficiencies and that important lifecycle processes may also be missing or misused.

We are especially concerned with statements regarding current smart pig technology that could mislead many to believe that smart pigs can reliably determine grooves or dents with stress concentrators. These are time dependent threats, whose time-to-failures are very difficult to predict, and are most likely to fail as ruptures. Advances in smart pig technology development are warranted in this important area. This author believes that the ideal proof test (usually for new pipeline) wishing to increase pipeline pressures to a design factor of 0.8) is a high pressure hydrotest (minimum 1.25 MAOP), which may not always be an option for pipelines in high elevation profile environments, coupled with 100% girth weld radiological inspections. This is the bar upon which alternative inspection methods or management processes must be compared, before any alternatives can be considered equivalent and pressures raised accordingly.

Given the higher operating stress levels for pipelines requesting pressure waivers, any overpressure events in excess of new pressure limits (MAOP plus approved accumulation pressure) must be quickly reported to PHMSA. All MAOP waivers from PHMSA should include a requirement that 49CFR191.23(b)(4) shall not be a condition to avoid timely (i.e., within 24 hours) reporting of an overpressure event above the waived limits. This reporting should not be a problem, but will assist PHMSA in proper use and confirmation of important risk management applications on higher stress pipelines that have received waiver approval.

Much of the discussion has focused on reducing the likelihood of a pipeline failure as pressures are increased. Prudence dictates that an important related issue, concerning the consequence of a failure, also be reviewed to complete any pressure increase waiver request. The potential impact zones associated with pipeline rupture at the higher pressures will be larger because of the higher mass flow associated with the greater gas density and pipeline inventory. Thus, inspections must incorporate additional segments of the pipeline and review population density that might not have been adequately captured in previous inspections/tests at the smaller empirically derived lower pressure potential impact circles utilized in current regulation. This is especially true for waiver requests where operating pressures are increased significantly in class 2 or 3 areas (or when class 1 become class 2 or 3 areas from development).

A reality check requires that appropriate impact zone calculations, especially for the higher pressures and larger diameter pipelines, based on more scientific calculations, be performed.
especially as the U.S. has no offset/proximity regulations. One such process is illustrated in the Corrib Pipeline report, covering a very unique, first of its kind, 20-inch, thick-walled gas production pipeline (D/t = 18.7), that as originally proposed could possibly experience pressures in the 5,000 plus psig range in very close proximity to civilians. As this referenced report clearly illustrates, even a relatively small diameter pipeline can have very large impact zones, well off the regulatory chart or potential impact circle empirical correlation as pressures or rupture mass flows approach the exotic. The Corrib Pipeline report further demonstrates areas in pipeline operation where poor or incomplete risk assessment approaches, even if permitted in regulation, can be very inappropriate or even reckless. It would be wise for any U.S. pipeline operator considering a significant pressure increase to demonstrate a high confidence that their impact circles are based on more defendable impact zone calculations, not minimum federal regulatory screening standards intended for another purpose.

The process upon which waivers are to be granted must remain public and for those pipelines that receive approval, the public along the pipeline right-of-way should be notified of the increase well in advance of the increase. Notification to those along the pipeline should go well beyond the potential impact zones defined in current federal pipeline regulation for reasons mentioned above. There are many international standards that have demonstrated operational success for the higher 0.8 design factor in lower population areas. While this wealth of experience is proper in representing various advances in pressure increases, we must caution that approaches in the U.S are significantly different, and a specific attempt to exactly duplicate these risk assessment approaches is inappropriate. As mentioned earlier, many international standards mandate setback distances from pipelines. There is no such requirement in U.S. pipeline regulations. This does not mean that important technical lessons learned from other countries should not be properly applied to pipelines in this country and visa versa. For example, this author believes that the U.S pipeline regulations lead the world in integrity management developments, which doesn’t mean further improvements can’t still be made in this critical area as well.

**Abbreviations**

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>BM</td>
<td>Bulk Modulus</td>
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<tr>
<td>C</td>
<td>Compressibility</td>
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<td>D/t</td>
<td>Pipe diameter to thickness ratio</td>
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<td>DRA</td>
<td>Drag Reducing Agent</td>
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<td>F</td>
<td>Design factor</td>
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<tr>
<td>FBE</td>
<td>Fusion Bonded Epoxy</td>
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<tr>
<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<td>HCA</td>
<td>High Consequence Area</td>
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<tr>
<td>HDD</td>
<td>Horizontal Directional Drill</td>
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<td>IM</td>
<td>Integrity Management</td>
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<td>INGAA</td>
<td>Interstate Natural Gas Association of America</td>
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<td>MAOP</td>
<td>Maximum Allowable Operating Pressure</td>
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<tr>
<td>MMSCF</td>
<td>Million Standard Cubic Feet</td>
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<tr>
<td>PHMSA</td>
<td>Pipeline and Hazardous Materials Safety Administration</td>
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<tr>
<td>SCC</td>
<td>Stress Corrosion Cracking</td>
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<tr>
<td>SMYS</td>
<td>Specified Minimum Yield Strength</td>
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