

November 6, 2001

Dockets Facility
U.S. Department of Transportation
Room PL-401
400 Seventh Street, SW
Washington, DC 20590-0001

Subject: Comments on Docket No. RSPA-00-7666; Notice 2, Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipelines)

We commend OPS’s efforts to foster a positive environment in developing needed regulation regarding gas transmission pipeline operation in certain high consequence areas (HCAs). The following comments briefly focus on several technical areas of concern related to gas transmission pipeline HCA regulation. Many of these comments were to be presented at the 9/13/01 Technical Pipeline Safety Standards Committee public meeting that unfortunately had to be canceled for obvious reasons.

Accufacts Inc. is a company specializing in risk management consulting on pipeline operations and design in areas of high population density or of environmentally sensitive nature. We advise industry, government agencies, and citizens of prudent practices which assist in appropriate management of risks for such assets. Our database draws from a wealth of pipeline operating and engineering experience, and information acquired from reviewing most major U.S. pipelines in today’s era of deregulation. As a point of reference, Accufacts Inc. played a key role in defining the technical requirements for the restart of the Olympic Pipeline following Bellingham, Washington’s terrible tragedy.

Based on the comments that follow, we believe that promulgation of a proposed HCA regulation for gas transmission pipelines may be premature at this time. Further discussion is warranted to correct serious technical flaws present in the current approach under consideration. We look forward to additional dialogue to develop a regulation that will help re-instill the public’s confidence and the industry’s credibility in this critically important infrastructure.

1) The current approach characterizing gas transmission pipeline corrosion as the only time dependent threat, manufacturing anomalies as static, or third party damage as random is dangerously simplistic, technically in error, and will create a major credibility gap with the public:

We see major risks for future pipeline incidents in the simplistic slant presented. Portraying corrosion as the only time dependent risk, manufacturing anomalies as static and third party damage as random, smacks of public relations spin that will not survive

cross examination and serious technical challenge. We highly advise a more prudent tact in the regulation that better reflects pipeline operations. Characterizing manufacturing and third party damage as time dependent may be more productive as well as factual. For the record, the following additional background may prove helpful:

Corrosion:

Obviously corrosion can be classified as a “time dependent” failure. What is not clear is that the time dependence is pipeline specific and depends on many factors that can vary over time. Traditionally, management practices would act as safety checks to ensure fairly long intervals before various types of corrosion became concerns. Historical corrosion trends don’t necessarily forecast future corrosion rates or selective corrosion attack, however. This is especially true in today’s era of increasing throughput which has a serious potential to increase internal corrosion if prudent management processes are not in play. In HCAs undergoing rapid development, we are also observing an alarming trend of third party encroachment interference of cathodic protection systems causing accelerated external corrosion rather than mitigation. Inspection intervals for corrosion should thus be tied to particular management practices, or the lack thereof, which dictate whether internal or external corrosion on a pipeline segment is the primary risk leading to rupture failure.

We believe the final investigation of the Carlsbad, New Mexico failure will underscore one significant point of caution related to corrosion. Re-inspection intervals based on steady-state corrosion rates extrapolated from long term historical trend data can be woefully inadequate. The consequences can be disastrous if the factors present can quickly accelerate corrosion either internal or external. Extremely long corrosion re-inspection intervals raise serious “red flags” in pipeline risk management programs as it is a rare pipeline indeed that has none of the corrosion risk factors.

Manufacturing/construction anomalies:

There is nothing static about certain anomaly threats introduced in earlier pipe manufacturing or construction processes. While focus in the docket has singled out pre-1970’s vintage electric resistance welded (ERW) pipe, both low frequency and high frequency, as one manufacturing threat of concern, it should be mentioned that not all ERW pipe is at risk. This anomaly of concern is not only manufacturer, but also mill-run, specific.

We also strongly advise a regulatory effort to address the role pipe steel toughness plays in pressure increase as well as pressure cycling induced rupture failure on gas transmission pipelines. Many of the older pipelines that are likely candidates for throughput increases are manufactured with less tolerant, lower toughness steel.

It is easy to believe the argument that gas pipelines are not as susceptible as liquid pipelines to pressure cycling induced anomaly growth or weld seam flaw growth failure associated with ERW pipe. At least three recent trends in the industry, however, place many gas transmission pipelines containing older pipe at heightened

or increased risk for time dependent failure, either anomaly growth or longitudinal seam rupture failure:

1. Increases in older pipelines' operating pressures. Historically, some of the older gas transmission pipelines have operated at pressure levels corresponding to stresses lower than allowable under Part 192, even though their MAOP was originally established based on Part 192. With greater demand for gas, these older pipelines may raise their pressures, thereby increasing the operating stress in the line. Note that under current regulations, these older "grandfathered" pipelines are not required to meet the pressure upgrade requirements of Part 192.555. Increasing either operating pressures or MAOP on existing pipelines should not be made lightly, especially if these pipelines traverse high consequence areas.
2. Inappropriate reliance on overpressure protection devices. Overpressure protection devices, which should be a "last line of defense," are increasingly being used as pressure control/regulating valves. Such an imprudent practice should be considered a serious rupture risk factor/threat especially if this is done in combination with "at risk" ERW pipe or lower toughness pipe. Inappropriate design, installation and operation of overpressure safety devices can significantly contribute to abusive pressure cycling on gas pipeline segments. It is worth noting that current and proposed federal regulations provide no minimum guidance in frequency of operation of such devices. As a further clarification, we place little value in pipeline pressure cycle studies, especially if pressure relief valve operation has not been well managed.
3. Significantly more variability in pipeline operations than in the past. FERC rulemaking (i.e. 636) has changed the operation of many gas transmission pipelines. In the past, most gas transmission pipelines operated at a reasonably steady pressure. FERC's commercialization or "marketization" of this transportation system, however, has moved many pipeline operations from a fairly steady base load to a much more variable flow because of changing delivery points. This factor has thus substantially increased pressure cycling of pipeline segments in recent years. Expect pressure cycling to accelerate as more gas fired turbine power plants plug into the gas pipeline infrastructure.

For the above three reasons, we anticipate an increase in cycling induced rupture failures in gas transmission pipelines and strongly advise risk management treat manufacturer anomalies as time dependent threats.

Third party damage:

We continue to observe serious gas transmission pipeline damage as a result of third party encroachment. Much of this damage is directly correlated to rapid development in high growth areas falling under the HCA definition. Such damage is, thus, not random, but can usually be traced to a lack of prudent management practices (i.e. in excess of current federal regulation) that gas pipeline operators should incorporate into their operations in such high risk areas.

We must caution that an encroachment does not need to hit a pipeline to cause serious damage that may rupture at a later time. A prudent pipeline operator will also manage against encroachment threats that may create abnormal loading or interfere with cathodic protection design intent, as well as screen for potential hits.

In focusing on hit damage, to date, both smart pigging and direct assessment technology have proven to be poor tools at identifying such damage. Since current reporting requirements do not necessarily require that third party hit damage be reported, there is no way for OPS to clearly monitor the amount of “sleeper” damage that has or is occurring. It is highly recommended that third party encroachment in HCAs be treated as a time dependent threat. Events such as lightning strikes and certain earth movements can be classified as random. It is time to face up to the fact that linked preventable events such as third party damage are anything but random.

It is worth noting that the 1994 Edison, NJ gas transmission pipeline failure was a third party hit (in a class 4 area) causing failure at a date much later than the hit. We anticipate an increase in gas transmission pipeline rupture failure from third party “sleeper” hits as pipeline operating pressures are raised and cycling is permitted to quickly placate greater gas demand in some areas.

2) Operator training and human error:

While we commend the efforts to define operator qualification/training prior to the rulemaking, we must caution that a wise pipeline operator does not rely on operating personnel to provide the first or primary level of protection against mis-operation of a pipeline. Proper design, installation and maintenance of safety equipment is historically the prudent primary level of protection against pipeline mis-operation. This design philosophy has served many different industries well, including the pipeline industry.

3) Tools to ensure pipeline integrity:

We take the fundamental approach that there are many tools to ascertain the various anomalies of concern that can cause rupture failure in a gas transmission pipeline. These tools include hydrotesting, appropriate smart pigging, and new, developing “other technologies” which can help determine the condition of a pipeline. We support and champion development of technologies that can assist pipeline operators in “real time” monitoring for possible third party hits. Absent such development, we must also stress the importance of further advancement in smart pig technology to identify third party damage; understanding that pigging is not real time feedback. We also support developing smart pigging efforts to assess longitudinal seam anomalies as we see a serious future need for this tool in HCAs.

The current HCA discussion related to direct assessment (DA) appears to lack focus and calls into serious question the effectiveness of this approach. At best, it appears that DA only addresses one risk of concern, corrosion. Again, a word of caution pertaining to DA and corrosion rate is appropriate. Since DA is heavily dependent upon historical data to forecast trends for other sections of pipe, this evaluation is only as good as the data available. As

mentioned earlier, there is a very high potential for historical data to miss new risk factors that can rapidly accelerate corrosion rates and cause rupture failure.

In dealing with pipeline integrity issues for gas transmission pipelines, we suggest a technical approach identifying the major risks of concern leading to rupture failure. This technical method would propose minimum Federal inspection intervals to assure the public that at least some safety net had been called into play. We propose a minimum inspection interval of 5 years for each of the major risks of concern that can cause ruptures. We are open to discussing the technical merits of increasing the inspection interval, but the discussion should center on the likely presence of time dependent anomalies of concern on a particular pipeline, and the ability of various methods to realistically identify these anomalies.

For example, if third party damage is a major risk of concern on a certain pipeline segment, running a smart pig may be inappropriate if the pig chosen is incapable of reliably determining third party damage. In such an example, mandating a smart pig run sets up a pipeline company's executive team and the public for a serious surprise no one wants.

Our technical team views hydrotesting as just one tool available in a toolbox to access pipeline integrity. We do not favor broadly mandating re-hydrotesting of existing pipelines, as we see this as a highly punitive measure that will not serve the industry or the public's interest. Depending on the risk of concern, hydrotesting may not be the best tool of choice. There are, however, certain unique situations on older pipelines where hydrotesting may be the only tool capable of identifying certain anomalies of risk. In these situations we recommend hydrotesting pressures in excess of minimum "new pipe" pressure levels required in current Federal regulations.

One final comment is warranted concerning gas supply impacts and testing methods. There is a need to seek a proper balance between testing intervals and gas supply impacts. We all need to not lose sight of the objective here. A major gas transmission pipeline rupture failure with serious loss of life can have a very draconian impact on gas supply, many times more than rational preventative measures.

Summary:

To summarize our main points:

- There are serious technical flaws in the current approach characterizing gas transmission pipeline corrosion as the only time dependent threat, manufacturing anomalies as static, or third party damage as random.
- Increasing pipeline pressures, whether operating or MAOP, in high consequence areas should get special regulatory attention, especially on older pipelines containing higher risk ERW pipe or low toughness steels.
- Operators should not be the first line of defense in preventing pipeline mis-operation.

- Pipeline integrity assessment should enable the choice of the proper tool that can best address the various risks of concern that can result in rupture failure. Minimum Federal inspection intervals should be mandated.

Thank you very much for your attention to these comments. I look forward to further discussion with OPS on these issues.

Sincerely,

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President

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