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Comments of the Pipeline Safety Trust on PHMSA Docket No. 2011-0023:
Safety of Natural Gas Transmission and Gathering Pipelines

Nearly six years ago, a 54-year-old pipeline constructed and owned by PG&E ruptured and exploded in a residential neighborhood of San Bruno, California. The explosion and fire killed 8 people, injured dozens, destroyed nearly 40 homes, devastated the Crestmoor neighborhood residents' sense of security and safety, and shook the confidence of many thousands of people living near gas transmission pipelines. Investigations following the explosion by the National Transportation Safety Board (NTSB), PHMSA, and California state regulators brought to light shortcomings in PG&E's construction, maintenance and operation of its pipeline system. The investigations also made clear safety shortcomings in federal regulations and many operators' implementation of those regulations. The NTSB issued numerous recommendations to PHMSA, to the industry trade groups, to the Secretary of Transportation, to PG&E, and to the state of California.

Congressional hearings were held following the explosion and in 2011 reauthorization of PHMSA's pipeline safety program included mandates to the agency to resolve regulatory shortcomings identified in those hearings. This year, PHMSA finally issued a proposed rule to respond to some of the NTSB recommendations and Congressional mandates.

In general, the Trust strongly supports these proposed rule changes. They are not perfect; they fail to address matters we believe are critical to improving pipeline safety, such as the creation of prescriptive standards for the placement of remote control and automatic shutoff valves, and standards for leak control systems on pipelines and associated facilities. Nevertheless, nearly six years have passed since the San Bruno tragedy and it is imperative that PHMSA issue these final rules to begin reducing industry-wide safety risks that were known before or became known as a result of the San Bruno investigations. Continued regulatory inaction would be unacceptable.

Costs and Benefits

One of the recommendations from the NTSB was to eliminate the so-called "grandfather clause" from the existing federal scheme. That clause allows operators of pipes installed before 1970 to base the maximum allowable operating pressure (MAOP) on the pipeline's operating pressure in the years between 1965 and 1970, rather than conducting hydrotests to determine the pipe segment's remaining strength. We whole-heartedly support the NTSB recommendation to eliminate this clause. In fact, we strongly prefer simple elimination of the grandfather clause to the unnecessarily complicated multi-optioned system PHMSA proposes, which would *still* allow certain pre-1970 pipelines to be operated at pressures not established as safe by a pressure test exceeding the MAOP plus a margin of safety.

In the wake of San Bruno, it became clear that PHMSA was unaware of just how many miles of line were operating under the grandfather clause and operating without adequate records of other information critical to safe operations. The extent of the problem surprised us as well: we believed that, at least for the 7 percent of natural gas transmission miles covered under integrity management rules, operators must have tested those lines and collected and maintained the critical safety data necessary to comply with the integrity management rules that require them to do so.

It appears that PHMSA has created the multi-optioned MAOP re-verification process in these rules in an attempt to reduce costs to the industry and not to run afoul of the cost/benefit requirements to which the agency is subject in the Pipeline Safety Act.[1] However, we believe the costs for verification of MAOP and data gathering, record maintenance, and data integration for lines subject to integrity management rules result from the original integrity management rules, not from this new rulemaking. Therefore, the Regulatory Impact Analysis should be amended to reflect a reduction in cost to remove these costs relating to lines within HCAs. If increased cost was the reason PHMSA chose not to outright eliminate the grandfather clause for lines within High Consequence Areas, we urge the agency to reexamine that decision in light of a properly amended RIA.

The explosion of PG&Es Line 132 and the subsequent investigation laid bare the degree to which that operator, and many others, were, and perhaps still are, relying on erroneous or non-existent records of critical aspects of the state of their systems, including the strength of the pipe. In short, these operators didn't (or don't) know what they had (or have) in the ground, despite clear direction under integrity management to perform the proper assessments and tests, gather the data, integrate the data, and maintain the records so that the information may be continually integrated into future operational and assessment decisions.

We believe it is very clear that an operator's information-gathering and assessment obligations under integrity management far exceed the obligations with respect to pipes that are not within high consequence areas. The specific knowledge gathered, retained, and integrated into threat identification, and risk and integrity assessment decisions is fundamental to the integrity management risk-based program. The presence of the grandfather clause in 49 CFR 192.619— an

[1] 49 USC §60102(b)(5).

operational regulation applying to all transmission pipelines—is irrelevant to determining an operator's additional obligations with respect to gathering and maintaining strength information about its lines in high consequence areas. The integrity management rules in Subpart O define those obligations, and they are substantial. *See additional discussion under our comments on proposed 192.506.*

The language used to describe an operator's obligation to know its system in the existing IM regulations and incorporated standards makes clear that the threat identification and risk assessment required of an operator first requires a thorough in-depth understanding of each system. For instance:

"An operator must identify and evaluate **all potential threats** to each covered pipeline segment." 49 CFR §192.917(a). "Potential threats that an operator must consider include, **but are not limited to**..." Id. "**All** threats to pipeline integrity shall be considered." ASME B31.8s (2004) at Section 2.2. "The first step in evaluating the potential threats for a pipeline system or segment is to **define and gather** the necessary data and information that **characterize the segment and the potential threats** to that segment." ASME B31.8s at §2.3.2. "**Comprehensive pipeline and facility knowledge is an essential component** of a performance based integrity management program" ASME B31.8s §4.1. (Emphasis added).

The Advisory Bulletin issued in 2011[2], as well as the testimony of a senior PHMSA engineer, testifying in the PG&E criminal trial currently underway in the Federal District Court for the Northern District of California, confirms our reading of the regulations:

> During his testimony, Nanney cited pipeline safety rules that appeared to place the responsibility of analyzing threats and risks of failure in gas pipes squarely on the shoulders of utility operators such as PG&E. "An operator must analyze the covered segment (of pipeline) to determine the risk of failure," Nanney said, citing Pipeline and Hazardous Materials Safety Administration requirements.
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> During cross examination by PG&E defense attorney Steven Bauer, Nanney was asked about the kinds of options PG&E could undertake in cases of uncertainty, such as missing or incomplete records, to determine the condition and operating risks of a particular natural gas pipeline. "You could do something else," Nanney testified. "You could pressure test your lines."[3]

The Advisory Bulletin makes it equally as plain that knowledge of a pipeline segment's characteristics is a critically important obligation imposed on operators by the IM

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[2] PHMSA Advisory Bulletin 11-01, "Pipeline Safety: Establishing Maximum Allowable Operating Pressure or Maximum Operating Pressure using Record Evidence, and Integrity Management Risk Identification, Assessment, prevention and Mitigation" 76 Fed Reg. 1504 (January 10, 2011).

[3] *San Jose Mercury News*: *San Bruno explosion trial: PG&E could have undertaken pressure tests for pipes* (http://www.mercurynews.com/business/ci_30047668/san-bruno-explosion-trial-pg-e-could-have) published June 23, 2016.

program :

> "One of the fundamental tenets of the IM program is that pipeline operators must be aware of the physical attributes of their pipeline as well as the physical environment that it transverses. These programs reflect the recognition that each pipeline is unique and has its own specific risk profile that is dependent upon the pipelines attributes, its geographical location, design, operating environment, the commodity being transported, and many other factors. This information is a vital component in an operator's ability to identify and evaluate the risks to its pipeline and identify the appropriate assessment tools, set the schedule for assessments of the integrity of the pipeline segments and identify the need for additional preventive and mitigative measures such as lowering operating pressures. If this information is unknown, or unknowable, a more conservative approach to operations is dictated." [4]

Even a decade after IM rule implementation, there are still thousands of pipeline miles for which the industry has missing or inadequate records or that have never undergone strength testing.[5] This fact, combined with the number of incidents in HCAs attributable to causes within the operator's control, suggests a widespread failure on the part of industry to meet the intent of integrity management. PHMSA should not accommodate those failures by providing a potentially less expensive optional means of gathering information about the remaining strength of the pipes in their integrity management programs. Likewise, the potential costs of maintaining the necessary records for their pipelines or of integrating data about their pipelines should not be attributed to this new rule. The obligations to gather *all* data necessary to identify and assess *all* threats to a segment within high consequence areas arose under the original IM rules, not this proposal. [6]

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[4] Advisory Bulletin 11-01.

[5] Notice of Proposed Rulemaking, 81 Federal Register 20729, April 8, 2016.

[6] The "non-mandatory" appendix to the incorporated industry standard suggests that the use of "conservative assumptions" may be acceptable in the face of unknown data. However, any effective integrity management program must entail a bare minimum of data that an operator must gather and maintain. That is, there must be certain characteristics of a pipeline segment for which no sufficiently "conservative assumption" exists in the context of a rule that requires the gathering and integration of all relevant system data necessary to assess the threats to the system. Notably, Advisory Bulletin 11-01 did not suggest that "the use of conservative assumptions is dictated," if information is unknown, but rather that "a more conservative approach to operation is dictated," such as pressure testing lines.

General comments

Applicability

There have been some media reports that some in the gas pipeline industry are concerned that some of the provisions of these proposed rules may inadvertently affect gas distribution systems. We urge PHMSA to review the language throughout the rules to insure that the applicability to transmission lines and gathering lines is as intended and as is stated in the preamble, which is to say that there is no applicability to distribution systems. Having said that, it is also important that PHMSA retain the definition of "transmission pipeline" as it currently exists in the regulations, to include any gas pipeline operating at a hoop stress of 20% or more of SMYS. Pipelines operating at a higher hoop stress should not be considered to be distribution lines, and should remain subject to the requirements applying to transmission lines.

What's missing

There are several items not included in the proposed rule that should be, and there are a few proposals that simply don't go far enough.

1) Automatic and remote control valves

The proposed rule does not include any new provisions relating to requiring standards for where automatic or remote control valves must be installed. Current regulations require the installation of ASVs or RCVs as an additional preventive and mitigative measure to mitigate the consequences of a pipeline failure in an HCA, based on a risk analysis considering the threats the operator has identified to each pipeline segment. The installation of ASVs or RCVs becomes mandatory only if such a risk analysis finds that the installation would be an "efficient" means of adding protection to an HCA. 49 CFR 192.935(c). Without additional definitional standards or guidance, this language allows each operator to determine the "efficiency" of the proposed installation, and essentially makes it impossible to enforce against an operator for choosing not to install the valves based on an "efficiency" determination. The absence of these valves certainly contributed to the amount of property loss in San Bruno and elsewhere and kept first responders from being able to enter the scene for much longer than if the flow of gas had been stopped in less than 90 minutes.

2) Leak detection/reduction of methane emissions

For reasons including safety, financial waste and the greenhouse effect of methane in the atmosphere, the industry should be eliminating methane leaks and unmitigated blowdowns wherever possible. Later in these comments, we discuss the availability and cost-effectiveness of mitigation options for non-emergency blowdowns. We urge PHMSA to include use of these mitigation options as an operational requirement in this rulemaking, and to undertake a rulemaking to establish leak detection standards for all jurisdictional pipelines and associated facilities.

Additional Section by Section comments

§191.1 Scope - (Adds gathering line reporting)
The proposed change will require operators of onshore gas gathering lines to submit incidents, safety related conditions, and annual summary data reports. The rule will accomplish this by eliminating certain exemptions under which gathering lines currently operate. We support this change, as it will provide the first information available to gauge the safety of the previously unreported lines and allow PHMSA to determine what additional safety regulations may be necessary. PHMSA should also require these lines to report data to the National Pipeline Mapping System and become subject to one-call systems.

§191.23 Reporting Safety Related Conditions
Congress required in the 2011 reauthorization that PHMSA require operators to report exceedances of their maximum allowable operating pressure (MAOP). This section and the following one impose that reporting requirement, which we support, so that PHMSA can begin gathering information about how often exceedances happen and whether additional safety regulations are required to limit them.

§191.25 Filing Safety related condition reports -
The proposed change relates to the imposition of a reporting requirement for MAOP exceedances and the procedures for filing those reports. We support the proposal.

§192.3 Definitions
The two biggest changes here are the definition of onshore gathering line, which proposes to repeal the use of the industry definition in API recommended practice 80 and includes a less ambiguous definition of gathering line. We support this change for the reasons given by PHMSA in the proposal.

The second major change is the inclusion of a definition for "Moderate consequence area", a new concept intended to be used to define the subset of areas where some integrity assessments are required on a very long reassessment interval and where MAOP verification and materials documentation is required. While these strengthen the rules that currently apply in this area, we have concerns with the subset of integrity rules PHMSA intends to apply to these areas, as we think that assessing them with in line inspection (ILI) tools without the requisite threat identification and risk assessment required for high consequences areas could result in the expense of tools being used without the operator, the public, or the regulator gaining any valuable integrity information that would lead to improved safety of the system. We revisit this concern below with respect to the substantive proposed rule.

§192.5 Class locations
This proposal requires operators to make and retain for the life of the pipeline documentation of how they determine the class location. We support this proposal, although it is disturbing to find that requiring this kind of recordkeeping is necessary, as it seems like a fundamental basis of safely designing and operating a system.

§ 192.8 Determination of gathering lines
As mentioned above under "scope", PHMSA is proposing to repeal the use of API RP-80 in determining what is a gathering line because of conflicting and ambiguous language in that RP. We support this change.

§ 192.9 what requirements apply to gathering lines?
This proposed section outlines some of the distinctions between various types of gathering lines based on size and location, as an attempt to respond to a GAO recommendation that PHMSA impose rules to reduce the risks of high pressure, large diameter gathering lines being used in new shale plays. Again, we do not oppose these, but think there should be additional regulation of gathering lines. If gathering lines are indistinguishable from transmission lines in every way except for their position in a system relative to other pipeline facilities, they should be regulated the same as transmission lines.

§192.13 General
This proposal makes important improvements to the regulation of all operators, by clarifying record creation and retention requirements and by imposing a requirement that operators evaluate and mitigate risks to the public and the environment as part of managing design, construction, operation, maintenance, and integrity, including management of change. We strongly support the inclusion of these changes in the final rule, as these seem to be basic obligations that should be met by an operator transporting hazardous material in neighborhoods, cities and environmentally sensitive areas.

§192.67 Records: Materials
This proposal responds to Section 23 of the 2011 Act requiring new rules to validate records used to establish MAOP. It will require operators to make and retain for the life of the pipeline records documenting tests, inspections, and manufacturing specifications. We strongly support this change along with all other recordkeeping rule changes.

§192.127 Records: Pipe design
This is another proposal designed to comply with Section 23 of the 2011 Act and will require operators to create and retain records relating to pipeline design and determination of design pressure. We strongly support.

§192.150 Passage of internal inspection devices
This proposal will incorporate by reference the NACE standard on designing for passage of ILI devices, which should improve the consistency of design and construction of line pipe to accommodate ILI devices. We support it, and believe that this is the type of situation where the adoption of industry standards is completely appropriate - to standardize the operation of tools capable of integrity assessments across operators and vendors. Such standards should still be made freely available to the public as a matter of due process and good government.

§ 192. 205 Records: Pipeline components
This is another proposal designed to comply with the record improvement requirements of Section 23 of the 2011 Act relating to determination of MAOP and will require operators to create and maintain for the life of the pipeline manufacturing and testing information for valves and other

components. We support this proposal relating to determination of MAOP to make sure that operators know what the physical and operational characteristics of the pipes in the ground are.

§192.227 Qualification of Welders and § 192.285 Plastic pipe Qualifying persons to make joints
Records relating to welder and jointer qualifications will be required to be created and retained. Again, we support this effort to improve recordkeeping.

§192.319 Installation of pipe in a ditch
This rule will require an indirect assessment of the coating of a pipeline immediately following installation to make sure that there has been no mechanical damage to the coating during construction. Records of this assessment must be created and maintained. We support this proposal, which is directly related to an incident caused by corrosion that resulted from poor construction practices that damaged the pipeline's coating.

§192.461, .465, .473 External corrosion rules
All three of these proposals are aimed at reducing damages to pipeline from external corrosion by clarifying the characteristics of coatings, require the remediation of any damage to the coating, monitoring external corrosion, and requiring surveys to determine if coatings might be affected by interference currents. There are far too many pipeline failures caused by corrosion, a cause that is completely within the operators' control. Given the high percentage of incidents that are still caused by corrosion, we strongly support these rules as an effort to bring down the number of those incidents that occur.

§ 192.478 Internal corrosion control - monitoring
As mentioned in the PHMSA analysis, between 2002 and November 2012, there were 206 incidents that were caused by internal corrosion, a number that is wholly unacceptable for a cause that is entirely within the control of operators. This proposal includes several measures that should help bring those numbers down by requiring operators to undertake monitoring of deleterious gas stream constituents and regularly reviewing their corrosion mitigation and monitoring program. We strongly support this proposal, as these provide an enforceable mechanism to hold operators accountable for future incidents caused by internal corrosion.

§192.485 Remedial measures - transmission lines
This is a records requirement specifying the retention of records of the pipe and material properties used in remaining strength calculations. We strongly support this proposal as integration of data into risk analyses requires that the information be available.

§192.493 Inline Inspection of pipelines
This proposal incorporates by reference some industry standards on performance of ILI assessments. We support this, but urge PHMSA to require that these standards, like all incorporated standards, be made available to the public free of charge.

§ 192.506 Spike hydrostatic pressure testing
Following San Bruno, the NTSB recommended that all pre-1970 pipes that had never undergone a pressure test be subjected to a hydrostatic pressure test including a spike test. This proposal is part of PHMSA's response to that recommendation, and while it is not fully responsive to the NTSB's recommendation, we support it. Following the NTSB report investigation, PHMSA issued

Advisory Bulletin 11-01, describing the detailed information gathering, threat identification and data integration obligations inherent in the integrity management program. We concur with and adopt the comments and recommendations of the Environmental Defense Fund in their comments on this proposed regulation, urging PHMSA to require implementation of specific methane emissions mitigation measures. See additional details under discussion of §192.624 and above in our discussion of necessary amendments to the RIA.

§192.605 Procedural manual
This proposal incorporates clarifications as to PHMSA's expectations for items to be included in an operator's procedural manuals, including means to prevent exceedances of MAOP. PHMSA determined this requirement was necessary when it received 14 notifications of MAOP exceedances in a bit over 6 months after issuing an advisory bulletin relating to reporting them.

§192.607 Verification of pipeline material
This proposal relates to the same issue as many others: Section 23 of the 2011 reauthorization act requires PHMSA to require verification of records used to establish MAOP. PHMSA determined through information gathered in annual reports that many miles of pipelines do not have adequate records to establish MAOP or adequately describe the physical and operational characteristics of the pipelines. PHMSA proposes to require operators to verify pipeline characteristics whenever pipes are exposed, and to propose criteria for material verification in higher risk areas of HCAs, class 3 and 4 areas. The proposal further requires creation and maintenance of traceable, verifiable and complete records relating to this verification. While we support this rule, we are quite frankly horrified at the number of miles of pipeline that are subject to integrity management rules for which operators have no verifiable information about their characteristics. To put it bluntly, after a decade of integrity management, they apparently don't know what's in the ground. IM rules require a threat identification and risk assessment as the foundation of an integrity management plan. On what foundation have operators been developing integrity management plans for over a decade when they have no records of what they've got in the ground?

§192.613 Continuing surveillance
Like the similar proposal in the hazardous liquid rule, we do not oppose this proposal to require inspection of pipes within 72 hours of a natural disaster. We simply marvel that such a rule is required at all (and it clearly is) when risks to pipelines are supposed to have been identified and planned for.

§192.619 MAOP
This proposal in response to an NTSB recommendation following San Bruno ensures that manufacturing defects only be considered stable in situations where they have been subject to a hydrostatic test for which the operator has and maintains traceable, verifiable records, of 1.25 times the MAOP. This proposed rule incorporates that recommendation and we strongly support it.

§ 192.624 MAOP verification
After the PG&E pipeline rupture and explosion in San Bruno, CA in 2010, the NTSB issued two recommendations relating to hydrotesting pipelines: first, they recommended that the so called "grandfather clause" allowing the continuing use of pre-1970 pipes that had never been

hydrotested be repealed and that all pre-1970 pipes be subjected to a hydrotest that incorporates a spike test. The Board also recommended that PHMSA amend its regulations so that an operator could only consider manufacturing and construction related defects to be stable if the pipe segment had been subjected to a post-construction hydrotest of at least 1.25 times the segment's MAOP. The Trust has supported implementation of those two recommendations in previous testimony before Congress. In simplified form, we agreed with the NTSB that if an operator has no record of a hydrotest of the strength of a pre-1970 pipe on which to base its MAOP calculation, then the pipe should undergo a hydrotest and the MAOP should be validated or changed. Similarly, if a known manufacturing or construction defect has never been hydrotested, it should be tested to a pressure of 1.25 MAOP, or it should be managed as if it is not stable.

In response to these two recommendations, PHMSA held a workshop and has published various flowcharts showing how it intended to require the verification of the integrity of these pipes - a process they have shorthanded to become IVP, or integrity verification process. They also gathered information from operators about how many miles of pipe line are in operation that fall into this category: pre-1970 pipe with no verifiable record of a strength hydrotest. Unfortunately, the answer was that there are a lot more miles than PHMSA previously believed. This somewhat complicated proposed rule is the outcome of that administrative process.

It is complicated in two ways: PHMSA is choosing to address these recommendations only with respect to certain pipeline segments, rather than a wholesale change applying across the board. So there are 3 sets of criteria that define the places where this new rule will apply. Then there are six (either a hydrotest or five other options) choices of methods to reestablish MAOP for the pipelines in these areas that are operating without (ever or since an in-service incident with certain specific causes) having had a hydrotest (or a record of one).

Our first concern with the proposal for 192.624 is that it does not meet the intent of the NTSB recommendation: it will only apply to certain pipelines, and not *all* pipelines. It will not require new verification of pipelines in non-HCA areas within classes 1 and 2 by completely rescinding the grandfather clause, and for those areas without adequate records of a hydrotest, it also will not apply in areas newly designated as an MCA which are capable of being assessed by an in line tool (piggable). The Trust strongly urges PHMSA to fully implement the NTSB recommendation and eliminate the grandfather clause entirely.

Our second concern is with the details of options that PHMSA provides operators to verify their MAOP. The proposed options to determine the strength of a pipeline and to re-establish its MAOP include 1) hydrotest and maintain the records of such a test; 2) down-rate the pipe (operate it at a lower pressure) 3) replace the pipe and hydrotest the new segment; 4) Run a smart pig and do an "engineering critical assessment" to establish a safety margin equivalent to that provided by a pressure test; 5) pressure reduction for certain small diameter, lower pressure lines or 6) other unspecified technology that provides an equivalent or greater margin of safety, providing PHMSA notice of the proposed use of such technology in advance.

Of those six, the two that are of substantial concern to the Pipeline Safety Trust are the fourth and sixth: ILI plus ECA and "other." As for the "other" option, the Trust has no objection to the availability of an alternative means of establishing pipe strength, so long as the request for permission to use it is treated as a special permit rather than a notice to PHMSA, and so long as the request is subject to public review and comment and the National Environmental Policy Act.

As for the option to run an inline tool and perform an engineering critical assessment to determine the remaining strength of the pipeline segment, we believe there are cases where this option should not be permitted as an alternative to pressure testing. Accufacts, Inc. prepared a white paper on engineering critical assessments for the Trust which we made available to the public on our website: http://pstrust.org/wp-content/uploads/2015/10/5-16-16-Signed-Final-Report-to-PST-on-ECA.pdf. We attach that paper hereto and make it a part of our comments. Consistent with the caveats in that paper, (and assuming PHMSA does not eliminate the grandfather clause entirely) we urge PHMSA to prohibit the use of ILI plus ECA as an alternative to a hydrotest for determining the strength of a pipeline segment where there are girth weld crack threats, significant stress corrosion cracking threats, or dents with stress concentrator threats.

Our final concern with the whole MAOP verification proposal is that it allows 15 years for operators to complete the assessments. For lines within HCAs, this is a timeframe that is entirely unacceptable, given that these are assessments that operators should have completed and records they should have readily at hand as part of their integrity management program. A slightly delayed effective date would be acceptable, but 15 more years is significantly too long to wait for industry to complete critical safety work that the rules have required for more than a decade. Moreover, individual operators and their largest trade group have shown themselves to be willing not only to take advantage of accommodations in the existing rule, but to try to game timeframes where there is any aspect of the time calculation that could arguably be perceived as subject to operator discretion.[7] In the face of such willful and reckless behavior, we urge each timeframe and deadline in the rule to be substantially shorter than proposed, and absolute, with no opportunity for operator discretion in any aspect of its calculation.

How will PHMSA inspect or enforce existing risk assessment, threat identification and preventive and mitigative measures in the meantime? Doesn't this proposed 15-year timeframe essentially give operators a free pass in these aspects of their programs for that period of time? PHMSA must reconsider this timeframe and must make clear to the public and to operators exactly what will be expected of them in the interim, and when expectations for inspections and enforcement will change.

We are pleased that PHMSA is beginning to respond to the NTSB recommendations and Congressional mandates to address these grandfathered pipes and records deficiencies, but we have some grave concerns about the details of this proposal: not completely eliminating the grandfather clause, not addressing it at all for lines outside moderate and high consequence areas, reliance on ECAs where the use of assumptions about a pipe's characteristics can result in erroneous strength estimates, and for the extraordinarily long implementation window provided in this proposal without any indication of how integrity management inspections and enforcement will go forward in the interim.

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[7] *Email Shows PG&E Knew of Problems Before Blast*, Nicolas Iovino, Courthouse News, http://www.courthousenews.com/2016/06/24/emails-show-pg-e-knew-of-problems-before-blast.htm, published June 24, 2016.

§192.710 Pipeline Assessments
One of the major shortcomings of existing gas pipeline regulations is that no integrity assessments are required for areas outside of High Consequence Areas - and those areas cover less than 7% of the mileage of existing transmission lines. This new proposal will require periodic integrity assessments of areas in a newly defined group of moderate consequence areas. Unfortunately, this proposal has several major shortcomings: It allows 15 years for the first set of assessments to be complete, and requires assessments only every 20 years after that - an implementation and reassessment interval that is simply insufficient to provide any real safety improvement. Its larger shortcoming is that, unlike the integrity management rule, this assessment rule does **not** require an operator to first identify the threats to these segments and develop a plan based on a risk assessment to manage and assess for those risks. This proposal would simply allow an operator to run an inline tool (or conduct a "direct assessment" in unpiggable segments) without ever determining what risks to the segment are and whether the tool chosen will assess for those threats. Without that fundamental risk assessment, this rule simply requires operators to pig and dig - once every 20 years, at that. Given the industry's existing use of in-line assessments beyond high consequence areas, and their stated commitment to extending in-line assessment use and zero incidents, this timeframe seems excessively generous.

§192.917 Risk assessment/ threat identification
This proposal applies only to those segments subject to integrity management rules, but it indicates that PHMSA is increasingly concerned about the quality of the risk assessments being performed by operators. This section proposes a number of clarifications to specify certain pipeline attributes, interactive threats, information, records and data analysis that PHMSA believes need to be a part of these risk assessments. We support these changes, since these clarifications and specifications will improve the quality of these assessments that are the foundation of each operator's integrity management program, and they will allow PHMSA to better enforce these expectations when they determine that operators are not complying. However, we believe these clarifications do not go nearly far enough to improve on the quality of risk assessments performed in operator integrity management programs.

In his report on the integrity management program to the Secretary's office[8], Rick Kowalewski discussed at length the risk assessment models used by most gas transmission operators and raised serious concerns about their quality, the choice of risk factors and weight assigned to them, as well as the quality of the data used in the assessments. Specifically, the report raises serious concerns with respect to the use of index-scored models, the selection of risk factors without analytical basis, the values chosen for individual risk factors contradicting existing data, cognitive biases leading to systematic errors, the use of numeric values to represent categorical variables, the use of integers to represent analog values, scaling results as if the change in risk is a linear function, weighting of risk factors, failing to account for the relationships between risk factors for

[8] A Report to the Secretary of Transportation: Pipeline Integrity Management: An Evaluation to Help Improve PHMSA's Oversight of Performance-Based Pipeline Safety Programs, Rick Kowalewski, October 31, 2013. First made publicly available on DOT website April 2016. https://www.transportation.gov/sites/dot.gov/files/docs/IM-PE_Report.pdf. Directing the completion of this report is apparently the Secretary's response to the recommendations from the NTSB that his office conduct an audit of PHMSA's implementation of the integrity management program. NTSB Safety Recommendations P-11-4 and P-11-5.

interactive threats, and several other concerns, each of which raise important issues with these analyses.

Perhaps the primary concern to the Trust and the public is that, absent reports like this, we have no way of knowing what these risk assessments look like, whether they are of any value, whether they work properly to identify the highest risks to a given pipe segment or system, all because they are kept by the operator, and are not made public, even following an incident that lays bare the failures of the analysis. The public never knows whether or how PHMSA inspects them, whether they have ever been back-tested following an incident, or whether they provide only a facade of meaningless math behind which operators may conceal serious data gaps, modeling weaknesses and, most importantly, weaknesses and errors in the safety programs that are founded on these analyses.

Mr. Kowalewski's report is attached here and should be considered incorporated into our comments. https://www.transportation.gov/sites/dot.gov/files/docs/IM-PE_Report.pdf

§192.921 Baseline assessments
This proposal adjusts the accepted and preferred methods of assessing pipelines under the integrity management rules. It explicitly limits the use of direct assessment to segments that are not piggable. We support the proposed changes.

§192.927 and 192.929 Direct Assessments
These two proposals essentially adjust the rules for the use of direct assessments to identify internal corrosion and stress corrosion cracking, and incorporate recent NACE guidelines for these purposes. We support these changes, and strongly encourage PHMSA to continue reducing the circumstances in which direct assessment is considered an acceptable assessment technique.

§192.933 Addressing integrity issues
The proposed changes to this section will adjust some of the repair criteria and timeframes for repairs, make explicit when an engineering assessment of stress corrosion cracking must be made, and makes adjustments to the definition of discovery of a condition. And once again, it proposes specifying certain records on strength calculations must be verifiable and maintained. We support these changes as responsible regulatory adjustments that reflect lessons learned from two major incidents.

§192.935 Preventive and mitigative measures
PHMSA is proposing to add a list of prescribed preventive and mitigative measures that an operator must consider in its risk assessment. We strongly support the inclusion of these items to provide additional guidance to operators about their risk assessments and to improve the quality of those assessments. The Trust also concurs with and adopts the comments and recommendations of the Environmental Defense Fund in its comments on this section, urging inclusion of leak detection efforts in this regulation.

§192.937 Continual evaluation and assessment
This proposal will require that the continual assessment and evaluation be consistent with data integration and risk assessment information to adequately identify and manage for the risks to each segment covered by the integrity management rules.

Data integration, threat identification and risk assessment are the foundation of managing the integrity of pipelines. We support these changes.

Mitigating methane emissions from non-emergency blowdowns

Several months ago, an operator sought special permits to allow dozens of pipeline segments to remain in place after the area had been identified as a Class 3 location and the pipelines no longer met the code requirements. In its application, one of the reasons the operator gave for wishing to leave the pipe segments in place was to avoid unnecessary methane blowdowns that would be required before the pipeline segments could be replaced. We objected to the applications on safety grounds and objected to the use of methane emissions being used to bolster a special permit application without any effort having been shown by the operator to identify mitigation measures to reduce those non-emergency blowdowns.

We have also long advocated on safety grounds for reduction in methane emissions in other contexts like system leaks throughout the gas transportation system. Because of our mutual interest in identifying mitigation measures for non-emergency blowdowns and to determine their cost-effectiveness in the context of this rule, we sought expert help from MJ Bradley and Associates (MJB&A) in partnership with the Environmental Defense Fund (EDF). The report produced by MJB&A is attached to these comments and should be considered incorporated herein. In short, the MJB&A report identifies a set of methods available to operators to mitigate the methane emissions from non-emergency blowdowns that are required in anticipation of hydrotests, repairs and replacements. The report further determines that to the extent blowdowns are necessitated by new proposals in this rulemaking, they are cost-effective to the operator.

We further adopt and incorporate the entirety of Section I of the comments of the Environmental Defense Fund to this rulemaking. The EDF comments elaborate on the mitigation methods, the methane emissions to be saved by each and the cost benefit analysis relating to implementation of the available methods. We join EDF in urging that PHMSA incorporate a new mandate into §192.506 or elsewhere to require the use of and reporting of such mitigation measures for non-emergency blowdowns, whether required under this rule, or in anticipation of repairs or replacements. Methane emissions should not be used as a reason to avoid necessary safety work on any pipeline.

Conclusion

The Pipeline Safety Trust is, first and foremost, in support of PHMSA finalizing a gas safety rule as quickly as possible. We have made several suggestions throughout these comments for changes we believe will strengthen and clarify the rules and improve pipeline safety. The investigation into PG&E Line 132's failure in San Bruno made clear the need for several critical improvements in the pipeline safety regulations. This proposal, while not perfect, begins the work to respond to that need. There are several areas where this proposal does not go far enough, or where it neglects to include a topic that is critical to protecting the public, like installation of automatic and remote control valves or leak detection. We urge PHMSA to undertake those rulemakings as soon as possible. We appreciate the opportunity to respond.