Summary of Discussions at the AGA Public Meeting
Rev 3
Chicago, Illinois
August 13, 2008

Introductory Remarks

Christina Sames, Vice President at AGA, introduced the meeting by describing the Distribution Integrity Management Program (DIMP) Notice of Proposed Rule Making (NPRM) as the most significant new regulation since distribution pipeline safety regulation began. The rule will cause changes in the way distribution operators do business. She noted the regulation is not yet final, several issues deserve further discussion (the primary purpose of the meeting), and comments to the docket by operators and the public can affect the content of the final regulation. She summarized the history of DIMP, including a study sponsored by AGF to focus on the magnitude and major contributors to distribution risk, and the multi-stakeholder Phase 1 study to develop ideas on the structure and content of a DIMP regulation. She described the purpose of the meeting as an opportunity to express concerns about the NPRM to help assure the regulation is as clear and effective as possible.

Phil Bennett suggested that participants raise all issues/concerns as the best approach to getting them resolved.

Craig Hoeferlin, VP of Operations at Laclede Gas, stated that operator programs are not just focused on compliance, but also on the need to improve performance. DIMP is expected to provide the foundation on which future changes to improve performance will be constructed.

Bill Gute, Deputy Associate Administrator for Pipeline Safety at PHMSA, encouraged those present to comment on the NPRM. He noted that DIMP has been structured to accommodate the significant differences among distribution systems subject to the new regulation.

Representing her State's point of view, Annmarie Robertson, Pipeline Safety Director for the State of Indiana, summarized her thoughts on:

- Areas requiring clarification include: data needed to characterize risk, treatment of human error, extent of documentation required for decisions, and details of needed performance measures.
- Some provisions in the NPRM were unexpected, including: assuring individual performance, plastic pipe data collection, deviations from periodic inspections, and enhanced damage prevention.
- Treatment of Master Meters, including: it seems appropriate to limit requirements, and the desirability of requiring Master Meters to install EFVs.
- Path forward: inspection & enforcement tools should be developed with states as lead, joint stakeholder group should conduct annual review of national performance metrics.

Panel 1 Development of a DIMP Plan

Mike Israni of PHMSA, who developed the NPRM, began by discussing the seven elements of DIMP, which mirror those developed in the Phase 1 effort. He noted that the principle underlying the rule is that an operator will recognize and fill safety program gaps based on its understanding of system risks. On the subject of damage prevention, Mr. Israni noted that the Phase 1 study recognized that state programs that contain nine elements appear to be most effective in reducing excavation damage, and that some but not all of the nine elements are under the control of the operator. He also noted that questions are posed in the NPRM on the value of permanently marking pipe and fittings. Different approaches to satisfying requirements of the DIMP regulation will be available for large and small operators. Because of the uniformity of their systems and limited staff, smaller operators will have the option of applying SHRIMP, a more focused approach to implementing DIMP. SHRIMP is currently being developed through APGA and will be available after the final rule has been released. Finally, Mr. Israni indicated that the target date for issuance of a final rule is December of 2008.

Steve Troch of Baltimore Gas & Electric (BG&E) presented concerns from the perspective of a large operator. The principal question is "What will I have to do differently?" While the NPRM has been written at a high level, GPTC guidance appears to address some, but not all, of its provisions. His primary concerns related to operator reporting requirements, the meaning of assuring individual performance, the basis for the performance measures and the logistics of additional reporting requirements - by an expansion of the annual report? Mr. Troch suggested that an operator needs to ask itself "What process changes will be needed to address the requirements of the NPRM?" These changes have the greatest impact and are the most costly. Additional issues he discussed include:

- Leak reporting (Is the intent to steer operators to consistent use of GPTC guidance? Will increased inspection identify more leaks thereby appearing to lead to weaker performance? Will the regulation cause the industry to increase its focus on leak backlog and repair timeframes? Does PHMSA intend for distribution operators to repair more leaks? Do PHMSA and its state partners plan to work together to streamline the reporting process?) The concern seemed to be that distribution operators may be led to monitor non-hazardous leaks and divert resources from addressing more significant public safety issues.;
- Damage prevention (what expectations are associated with "enhanced" damage prevention? what will the states look for in operators and PHMSA look for in the states? inconsistent state requirements on the issuance of tickets could lead to inconsistent basis for comparison among operators in different states; what is the definition of damage? (some definitions are likely to lead to reporting of events not previously reported, appearing to represent poorer performance));
- Assuring individual performance (What is the framework? Is this concept focused only on operator's people or is it broader? What impact will it have on paperwork? What does PHMSA expect operators to do beyond complying with existing regulations?);

Additional reporting (Is new reporting to be consolidated with existing reports? How are key terms defined? How will data be used in comparisons?).

Mr. Troch's concerns focused on two underlying issues: (a) how we can accommodate situations where an operator makes decisions it believes will leads to improved performance, but the early manifestation of implementing these decisions is the appearance of worse performance; and (b) how we can ensure that comparisons among operators are not made on an inconsistent basis, leading to inappropriate comparisons.

John Erickson of APGA described his constituency as being 700 very small operators typically with revenues of less than one million dollars per year. The implication of the size of these operators is they do not have resources to understand or implement complex regulations. These operators need great clarity in what they are expected to do. The small operators will have the option of following 'SHRIMP' to comply with DIMP regulations. SHRIMP will simplify the approach smaller operators use to identify threats and risk mitigation opportunities. SHRIMP is currently being developed through APGA and will be completed once the final rule is released.

Bob Leonberger, State Pipeline Safety Program Manager for Missouri commented states will be challenged to translate requirements of the regulation into simple inspections for use with the smallest operators. He also expressed his belief that the current Plastic Pipeline Data Committee (PPDC) is better than a newly created system that could lose access to current data and expertise. He believes improvements to the current system should include reporting on materials beyond plastic. With respect to performance measures, Mr. Leonberger noted the need to define hazardous leaks and damage if reported data are to have meaning. He also expressed the thought that some distribution operators also operate transmission piping, and that separate integrity management regulations with separate decision bases could lead to inappropriate decisions on how best to expend resources to improve safety. There is a need for an internally consistent decision process to assure this doesn't happen. Mr. Leonberger suggested operators with distribution and transmission systems should be given the option of allocating resources to activities that will best address pipeline and public safety. In addition, Mr. Leonberger suggested that, now that DIMP is out, transmission lines that are in distribution systems and operating under 30%SMYS can be considered under DIMP. Other issues addressed by Mr. Leonberger include:

- Assuring individual performance should be removed from the regulation until what it means can be more clearly described.
- Requirements on EFV installation need to be clarified for "single residences"
- Small operators need a checklist on what they need to do
- New construction and replacement of piping should be covered in DIMP

Phil Sher, Pipeline Safety Program Manager for Connecticut, began his discussion by posing the question - why, given the absence of data, do we believe small operators are less risky? If requirements in the regulation are affected by this assumption, a better case needs to be made. Mr. Sher also questioned:

- Why LP systems are excluded from the requirement to install EFVs (they should be included)
- What the requirement to assemble data about a system really means (only data relevant to understanding risks are needed)
- Why the NPRM is requiring every decision to be documented (decisions should be covered in proceduralized decision processes, and only decisions relating to meaningful improvements in safety should be included)
- The basis for requiring records be maintained on all appurtenances
- The possible need for multiple plans for operators with systems in several states - possibly leading to charging rate payers in one state for improvements in another state
- What "enhanced damage prevention" means

Andrew Lu summarized the presentations with two points:

- Documentation requirements are excessive - only significant changes should require documentation
- Definitions need to be clarified, including “damage”, “tickets”, and “enhanced damage prevention”

Questions & Comments following Panel 1

Bob Naper, National Grid, commented that “damage” should be defined as limited to excavation damage, suggested the definition match that for annual reporting. Andrew Lu, AGA responded “damage” should not be limited to leak-producing damage. Mike Israni, PHMSA stated PHMSA considers “damage to be equivalent to excavation damage, and agreed its definition should be broader than leak-producing damage. Mike Israni noted that the definition for “damage” includes any damage that occurs during excavation activities. Bob Naper replied he was concerned that strengthening reporting practices would be perceived as resulting in degraded performance (reporting more can look bad, absent discussion of the context). Mike Israni said PHMSA is trying to differentiate “leaks” from “damage”.

Joe Beerley, PECO Energy Company, asked whether FAQs and protocols will be part of the inspection process as they were in gas transmission IMP. Mike Israni replied the states have the lead, but PHMSA is working with the states to address shared needs and PHMSA will need to develop an inspection approach to address operators within its jurisdiction. FAQs are currently being used to try to describe the intent of the DIMP NPRM. PHMSA will also offer training in provisions of the regulation after it is finalized.

Lee Reynolds, NiSource, asked whether PHMSA intends expectations from transmission IMP (on program elements of similar nature) to be applied to the distribution operators through the use of protocols. Mike Israni responded element-by-element documentation has proven useful as a consistent description of the basis for and assumptions made in decisions.

An industry representative (name unavailable) asked about limitations that would apply to use of the less restrictive requirements for small operators. Mike Israni replied the cost-benefit analysis assumed operators with less than 12,000 services are considered small, but that same constraint might not apply in compliance inspections.

John Erickson, APGA, commented that the most burdensome requirements for small operators are those related to documentation. To ease the documentation burden on small operators, SHRIMP will provide a checklist to document threat identification. Other elements need to be addressed thoroughly by all operators.

Panel 2 Plastic Pipe Data Collection

Richard Sanders, Director of PHMSA Training & Qualification, provided background on the origins and initial focus of the PPDC. It was initiated in response to an NTSB concern on slow crack growth in plastic piping. Plastic piping today represents approximately half of the installed distribution mains. To allow rapid collection and analysis of data, the PPDC was chartered to allow anonymous submittal of data, included broad stakeholder evaluation of what the data meant, and was administered by AGA. PPDC has proven to be very successful. It has collected and analyzed over 16,000 data points, and the initial problem it was organized to address has been solved. The data collected by PPDC is in-service failure data, excluding third party damage unless the failure is delayed - resulting from a stress riser caused by the hit. Mr. Sanders commented that to be as useful as it might be, PPDC would need to collect data on failure causes based on a root cause analysis. This could add significantly to the cost of submitting data which would have an unknown effect on the amount of data submitted in a voluntary program.

Tim Lauder, Public Service Electric and Gas, described PPDC. Operators submit data voluntarily, retaining their anonymity and the level of participation has been significant. The PPDC volunteers account for roughly 77% of the installed plastic mains and 83% of the installed plastic services. A group of 16 representatives from a broad range of stakeholders including NTSB, PHMSA, NAPSR, NARUC, AGA and APGA meet twice each year to evaluate the lessons that can be extracted from the data. Each representative can raise questions, and the data base is exercised to try to answer the questions. The result is an annual report posted on the AGA web site for viewing by interested parties. The data itself is confidential, but the results of the analysis and responses to questions from participating organizations are contained in the annual report. Accuracy of the data is critical to the success of the process, and data accuracy is assured through interaction with the submitting organizations. Also critical to the effectiveness of the PPDC are the knowledge and expertise of the sixteen members who meet to extract lessons from the data. The data review that is completed by the 16 representatives has strengthened our understanding of problems that industry was aware of with specific materials.

Karen Lively, Performance Pipe, presented the perspective of pipe manufacturers. Polyethylene was used early because of its desirable properties. While some of the early polyethylene experienced slow crack growth, some was manufactured so that it satisfies current material standards. Pennsylvania Notched Test (PENT) tests are used to characterize the susceptibility to slow crack growth. These tests are currently showing a life (based on failure by slow crack growth) of thousands of years. Ms. Lively pointed out that plastic pipe is currently permanently marked, but the markings have so much information that reading them is unwieldy and markings are structured differently based on the requirements of individual operators. If we are going to move to marking fittings, then it would be useful to specify a nationally consistent marking standard consistent with the needs of operators.

Darin Burk, Pipeline Safety Program Manager for Illinois, noted that the proposed rule does not identify a problem with the current method of collecting data regarding plastic pipe. A problem or concern must be clarified so that all stakeholders involved can better understand what can be done within the PPDC and what may need to be done that is beyond the scope of the PPDC. Mr. Burk also noted that the definition of damage must be clarified to better understand PHMSA's intent. The requirement that all failures must be reporting within 90 days is onerous for the operators as well as the regulatory community. Considering the large volume of information that is already processed by state regulators and local commissions, the stringent reporting interval proposed will place an undue burden on limited regulatory resources. Mr. Burk suggested that the reports be filed on a semiannual basis. Considering the limited regulatory resources on the local level, Mr. Burk suggested that PHMSA collect the data or assign an agency to collect the data on their behalf. The marking standard is a good idea, but is difficult to enforce. Regulators don't have jurisdiction over the manufacturers who create the ~~fittings,~~fittings; they have no way of knowing whether of not they are marking the plastic materials correctly. Mr. Burk also posed a set of questions for consideration prior to finalization of the regulation. His questions included:

- Why do we want to collect data only on plastic pipe & fittings?
- What types of failures do we want reported (e.g., related to material, fabrication, operating environment)

In addition he commented that if we are going to require marking, we need to prescribe a standard for the marking.

Phil Bennett, AGA, attempted to tie the issues discussed by other speakers together. He said the driving questions behind any change in data collection and analysis should be "What data collection and analysis is prudent to assure continued improvements to safe operation? Does PPDC satisfy the need?" Mr. Bennett stated that, as the rule is currently written, the federal database would only be accessible to the regulator, and analysis can only be provided by the regulator. A voluntary PPDC will not exist alongside a mandatory, federally rule plastic material database. Does PHMSA wish to end the PPDC? Mr. Bennett stated that PPDC has been shown to work. Improvements should be considered in communicating to the public as well as in the range of information communicated to operators. The current structure can accommodate these needs without significant change. If PHMSA took over collection of data, does the range of expertise and resources exist to do a comparable job to that done by PPDC? If data collection were made mandatory, then the conditions under which PPDC operates would likely be violated, and much of the data collected and available for analysis would become unavailable. The voluntary status of the PPDC helps to keep all of the parties actively involved in the process. Keeping in mind that the PPDC database accounts for roughly 83% of the installed plastic services, PHMSA must ask what is the benefit of major changes to get 17% more data. Mr. Bennett noted that, if the database were made mandatory, a large number of small operators would be submitting data without the appropriate QA/QC procedures in the place. Expanding the scope of PPDC to all types of materials would lead to major problems, including greater complexity and increased resources needed to analyze the data. The volume of the data submitted under a mandatory system extended to all materials would cause assuring quality and analysis to be impractical. There may be less than 10 manufacturers of plastic pipe. There are unknown thousands of manufactures of other components.   Mr. Bennett suggested the best path forward would be to make a few modifications to PPDC but maintain its voluntary nature and supporting infrastructure. Candidate changes include:

- New independent administration
- Provide stakeholders improved graphic analysis of the data
- Produce a more detailed annual report for communicating the results of the analysis

The purpose of these changes would be to improve the usefulness of PPDC for understanding of problems and to continue to restrict its usefulness for use by litigators. The voluntary model is similar ~~to voluntary~~to voluntary ~~system used~~system used by FAA - a system administered by NASA. Mr. Bennett implied that a mandatory system could be the focus of litigation which would considerably increase the resources needed to support its operation.

Questions & Comments following Panel 2

Bob Leonberger asked why we shouldn't simply make PPDC mandatory. This led to a discussion among panel participants.

- Phil Bennett replied that it might be possible but would be cumbersome, further 83% of pipeline is currently in the systems operated by participants. Mr. Bennett also noted that making the PPDC mandatory will negate many of the benefits of the current system. What is the benefit of major system changes to increase participation to 100%?
- Richard Sanders noted that non-participating operators may be experiencing a greater number of failures than those participating, and that there is some evidence that the population of failures experienced by non-reporting operators may be different from those of reporting operators.
- Phil Bennett suggested that rather than requiring all operators to submit data, they be required to gather and retain the needed data.
- Richard Sanders expressed reservations over the value of mandatory data reporting and stated that PHMSA's key concern is lack of communication of implications.
- Mike Israni suggested that PHMSA might have a third party administer data collection and data analysis.
- Phil Sher observed that we should have a clear idea of what problem we are trying to solve before mandating a solution. In the case of mandatory reporting, it isn't clear we have that understanding.
- Mike Israni observed that the Phase 1 report made it clear we need to assure sharing of information relevant to pipe integrity, and that recent experience with compression coupling failures has led PHMSA to believe there is a need to understand a broader set of failures mechanisms than simply material related failures.
- Christina Sames clarified that PPDC has many diverse stakeholders with access to the PPDC data. These stakeholders include all aspects of the regulatory community, so they can influence PPDC data analysis. These stakeholders analyze the data, summarize the results of the analysis and broadly report these results. Any participating group can pose questions to be addressed through analysis of the data. Is there a real need for expanded data gathering? What would be its purpose?
- Karen Lively observed that there is a gap in communications. There are some issues involving installation we seemed concerned about. PPDC is designed to address materials issues, not a broader set. Ms. Lively said that PPDC participants can continue to discuss how to better address the communication problems that have been identified, to better inform the industry as well the regulatory community.
- Richard Sanders agreed noting the compression coupling failures in Ohio were not reported since they involved non-plastic materials and construction practices. Tim Lauder questioned the usefulness of mandatory reporting.
- Bill Gute observed that PPDC doesn't disclose reporting operator or the manufacturer, so the data could be made available to the public.
- Rick Lonn, AGL asked whether PPDC looks at the impact of maintenance practices (e.g., pinching off flow) on reliability.

- Karen Lively noted that older materials are affected by maintenance practices, but newer ones aren't.

Discussion on the requirement to submit data within 90 days was initiated by Bill Manegold, Pacific Gas & Electric, who observed that operators don't know the cause of a failure until they complete the repair and analysis. Therefore the 90 day rolling requirement would be a burden and potentially contribute to less accurate reporting; report every six months would be less burdensome and probably more accurate.

Finally, Mr. Israni agreed that there is a need to clarify the functionality of pipe and appurtenance marking.

Panel 3 Prevention through People (PTP)

Mike Israni, PHMSA, began by putting PTP in perspective. He noted there are several existing regulations that address assuring people perform effectively in preventing or mitigating events, but that all possible areas are not covered by the regulations. Examples of currently uncovered areas include: new construction is not included in the OQ regulations, control of the design of above ground piping to minimize the impact of auto hits, there are no requirements to take action to minimize the impact of rogue excavators with a history of pipe hits (e.g., cable TV provider installing underground cable), and interdivisional communication of integrity-related information is not regulated and often limited by stovepipe organizational structures. If GPTC were to develop guidance it would, as in other aspects of the regulation, provide the needed clarity for operators to implement appropriate provisions.

Rick Lonn, AGL Resources, commented that from his perspective, the concept seems to have some merit and is worth further discussion. However, at this stage of development, PTP seems to be a solution in search of a problem. He questioned whether there is a real need in the light of other existing regulations. If the concept has merit, any approach to addressing it will need to consider several questions such as:

- Is a solution within the control of the operator? Is action physically and economically feasible?
- Does a proposed solution add value?
- How would candidate solutions be audited?
- How significant are the related risks?

For example, failures associated with corrosion and materials & welds are affected by human factors only at the time of construction. Failures caused by natural forces and other outside forces are beyond the control of the operator. Failures caused by equipment and operations are directly affected by human factors, but this is taken into account with operator qualification (OQ) and training. Excavation damage is directly affected by human factors, but the effectiveness of each operator's excavation damage prevention program is reflective of all of the stakeholders and the enforcement provided, not just the actions of the operator.

Mr. Lonn reviewed the threats from the Phase 1 report to characterize the contribution of people, and concluded, given the assumption that only operator staff could contribute to the solution, and then only if they were working within the bounds of the operator's traditional functions, there were no significant improvements operators could effect on risk beyond what they currently do. Industry is doing a tremendous amount to address the personnel component, so putting it under one umbrella simply confuses the issue. Therefore PTP doesn't clearly add value. Certainly an operator can do more to affect known threats, but the role of PTP in determining these actions is far from clear.

AnnMarie Robertson, Pipeline Safety Chief for the State of Indiana, commented that she agreed with the comments offered by Mr. Lonn. PTP is still just a concept, and as such is too vague to include in the DIMP regulation. Further she said the provision would be very difficult to enforce since the scope is not clear. Finally, Ms. Robertson suggested the concept may be worth further discussion by a specially constituted group outside the DIMP regulation.

Andrew Lu, AGA, summarized and expanded upon the comments by stating that GPTC feels it could not develop implementation guidance because the language is vague and ambiguous. Existing requirements seem to cover the field of personnel involvement, and there is no clear basis to address the issue of fatigue under DIMP. Further, PTP was not mentioned in the Phase 1 report. However, AGA would be willing to continue discussions to clarify the PTP concept outside of the DIMP effort.

Questions & Comments following Panel 3

Mike Israni noted that developing GPTC guidance with the current level of clarity of the PTP concept might be difficult, but that this clarity could result from further discussion among interested parties. In addition, Mr. Israni reiterated that the OQ regulation does not apply to new construction, a phase of the life cycle of a pipeline that often causes many failures in new pipelines.

Andrew Lu reiterated AGA's willingness to explore any gaps in the current regulations, but outside DIMP where the issues can be considered carefully. This led to a number of comments supporting the need to further investigate the need for PTP outside the context of the DIMP rulemaking.

- AnnMarie Robertson reiterated her position that the PTP concept makes the implementation opportunities endless, therefore the provision would be unenforceable.
- Bob Leonberger, State of Missouri, noted that the implications of PTP are so broad that we should really focus on each individually to assure requirements and expectations are clear.
- Gary White, PI Confluence, noted that the PTP concept originated from work completed within the Coast Guard. All individuals affected by the PTP concept were within the jurisdiction of the Coast Guard and, therefore, accountable for their actions. Neither the operators nor PHMSA has jurisdiction over all the stakeholders affected by the implementation of the PTP concept in the pipeline industry.
- Phil Bennett, AGA, questioned whether PTP is intended to broaden the operator responsibilities (and related liability) to areas beyond those currently addressed by employees.
- Marti Marek, Southwest Gas and Chair of GPTC's Distribution Committee, acknowledged that she is the source of the opinion that GPTC could not develop guidance for the PTP requirement given its current ambiguity, and that the issue should be separated out for further consideration separate from DIMP. Ms. Marek also noted that GPTC guidance documents are always crafted

after the final rule has been issued, therefore GPTC cannot yet not write guidance for the NPRM PTP requirements.

- Another industry representative (name not available) commented that PTP seems to be designed to separate out one category of preventive and mitigative measures for special consideration, and that this seemed inappropriate given our current understanding of the contribution of people to distribution risk.
- Yet another industry representative questioned where this provision would end up in the long term. Would PTP be integrated under a separate structure, thereby adding to the operator's burden?
- Ram Veerapaneni, DTE Energy, commented that since the provision was insufficiently clear to support development of GPTC guidance, pursuing it further would give PHMSA a bad name.
- Bob Naper commented that that the data don't exist to support measurement of the success or failure of PTP.
- Finally, Christina Sames, AGA, commented that PTP is just too vague, and the concept needs further investigation to evaluate its potential value, and this investigation should be in concert with the transmission pipeline industry.

Panel 4 Alternative Inspection Intervals

Jim Anderson, PHMSA, began the discussion by presenting provisions of the NPRM related to alternative inspection intervals. The focus is on current regulations that stipulate a periodic time frame - so called "time-defined" requirements. Since the current inspection intervals are not risk-based, the operator may be required to inspect on time intervals that do not augment pipeline safety. Deviations from the specified intervals can only be made with documentation and engineering analysis to support risk-based inspection intervals. The operator must prove a "satisfactory" level of pipeline safety.

Mike Israni clarified that states will be delegated with the power to approve alternative inspection intervals and "waivers/special permits" will not need PHMSA approval.

Phil Bennett, AGA, stated that AGA supports the language in the NPRM. The technological ~~advances that industry has taken over the past thirty years have greatly improved pipeline safety and, in certain circumstances, allows~~advances that industry has taken over the past thirty years have greatly improved pipeline safety and, in certain circumstances, allow the operator to perform maintenance and assessments and a less frequent basis. This portion of the proposed rule is designed to make the rule cost beneficial and improve pipeline safety. If the operator wants flexibility, this means the operator will have to complete additional work to support alternative inspection intervals. He noted the some states may be less enthusiastic, and that any proposed changes need to be made with full engagement of the state regulatory agencies. This engagement needs to include a thorough analysis of the data by the operator to develop its case - the data should drive the case for proposed changes and the decision to accept or reject the proposals. Some operators may choose not to invest the resources in the analysis needed to support alternate inspection intervals. Mr. Bennett noted that industry has already started alternate inspection interval research regarding atmospheric corrosion. This research is ongoing, but is providing operators with additional inspection options to assess atmospheric corrosion. As with atmospheric corrosion inspection intervals, work on alternate inspection intervals will require research and cooperation among all of the stakeholders.

Art Shapiro, National Grid, noted there may be different approaches to addressing alternative inspection intervals, and was not ~~sure of~~sure ~~the~~of the role PHMSA might play in reviewing or approving alternate intervals. He noted that data analysis is underway for atmospheric corrosion inspection intervals, and that variations on the appropriate interval seem to depend on the environment in which the pipe operates. Mr. Shapiro noted the practical issue of how to pursue alternatives, and questioned whether there may be potential alternative.

Phil Sher, Pipeline Safety Director from Connecticut, clarified that if a state accepts an application for an alternative, PHMSA probably wants no say in the decision oversight. He presented the NAPSR position that alternatives should be considered based on a net safety improvement resulting from DIMP-related changes, including new additional and accelerated (A&A) practices and requested waivers. The local (State) authority will be the one who makes decisions on alternatives, including the basis on which the requests and decisions will be made.

Questions & Comments following Panel 4

Tim Lauder, PSE&G, asked whether there is any incentive to the states to make the process of requesting alternative inspection intervals work. This led to a discussion requesting further clarification.

- Phil Sher responded that Connecticut is willing to consider any request that demonstrates improved safety and helps the ratepayer. Mr. Sher also noted that the process will not change dramatically from a state regulator standpoint, as the commission will make the final decision and operators will still have to go through the waiver process.
- Bob Leonberger noted that in Missouri the Commission will be the decision maker.
- Phil Bennett stated that decisions should be risk-based and data-driven. As an industry, distribution operators can probably develop a template for requests based on an understanding of the impact on performance.
- Jim Anderson offered the opinion that some regulators are looking for trade-offs in which savings from alternative inspection intervals to address other higher risk areas.
- Christine Sames, AGA, said industry would like to see data-based decisions, and visible reallocation of saved resources to higher risk areas.
- Mike Israni, PHMSA, reinforced that PHMSA feels that the onus is on the operators to provide the risk analysis and the engineering analysis. PHMSA's intent is that operators will be able to reallocate their resources as a result of DIMP. The reallocation of resources would allow operators to alleviate a portion of the burden imposed by DIMP. No guidelines are currently in place; PHMSA is working with its state partners to develop guidelines. These discussions are in the beginning stages and will continue to evolve when the final rule is issued.

Bill Gute, PHMSA, stated that PHMSA will be following up with the states after the final rule is issued to determine how the process is going and to see if any changes need to be made.

GPTC Comments

Glen Armstrong, GPTC co-chair, described the status of the guidance. Current draft guidance was developed before the NPRM was issued, and therefore does not cover every part of the NPRM, but only those topics addressed in the Phase 1 report. The guidance, as developed, is considered to be good, even if incomplete. Consistent with the ANSI process, the guidance will go out for letter ballot on August 18 and for public comment on September 8. If there are significant comments, then the group that developed the guidance will be reconvened to address the comments. GPTC will not issue any additional DIMP documents until after the final rule has been issued.

In response to a question on the enforcement of the DIMP regulation and the role of the GPTC guidance, Mike Israni of PHMSA noted the guidance is not referenced in the regulation. It was developed with broad stakeholder participation, and as a consequence, state regulators will no doubt consider operator programs in the light of the implementation choices presented in the guidance.

Conclusion

Christina Sames of AGA expressed appreciation for the good interaction at the meeting, and noted the apparent good agreement between the perspective of the states and those of the industry. She noted that, in the light of the importance of the regulation, PHMSA should consider allowing additional time for comments. AGA will officially request additional comment time.

Attachment 1
Agenda for the AGA Meeting on DIMP
Chicago, Illinois
August 13, 2008

Wednesday, August 13, 2008

8:00 am Opening Remarks - Phil Bennett, AGA

- Review workshop structure and meeting objectives
- Review AGA anti-trust guidelines

8:15 am General Comments on DIMP NPRM - Christina Sames, AGA

8:30 am Perspective of Operations Executive - Craig Hoeferlin, Laclede Gas

8:45 am General Comments on DIMP NPRM - Bill Gute, PHMSA

9:00 am State Regulatory Perspective - Annmarie Robertson, Indiana Commission

9:15 am **Panel 1:** ***Development of a DIMP Plan***

Moderated by: Andrew Lu, AGA

Presentations and comments will focus on the 7 elements to be included in a DIMP Plan. Discussion will focus on data integration, risk assessment and risk management, and records documentation (as noted by 192.1015). The panel will also include discussion on NPRM's requirement for operator to include a process to identify any potential performance issues with compression couplings.

1) Mike Israni, PHMSA
2) Steve Troch, Baltimore Gas & Electric
3) John Erickson, American Public Gas Association (APGA)
4) Bob Leonberger, Missouri Commission
5) Phil Sher, Connecticut Dept of Utility Control

10:45 am **Panel 2:** ***Plastic Pipe Data Collection***

Moderated by: Phil Bennett, AGA

Presentations and comments will focus on the NPRM's proposed requirements for mandatory plastic pipe failure reporting. Panel will also explore answers to PHMSA's concerns with the transparency and accessibility of the existing PPDC, which is administered by AGA.

1) Richard Sanders, PHMSA
2) Tim Lauder, PSE&G
3) Karen Lively, Performance Pipe

4) Darin Burk, Illinois Commerce Commission

1:00 pm **Panel 3: *Prevention through People (PTP)***

Moderated by: Andrew Lu, AGA

Presentations and comments will focus on the NPRM's proposed requirements for DIMP plans to include a section titled "*Assuring Individual Performance*", as noted in 192.1007(d).

1) Mike Israni, PHMSA
2) Rick Lonn, AGL Resources
3) Annmarie Robertson, Indiana Utility Regulatory Commission

2:45 pm **Panel 4: *Alternative Inspection Intervals***

Moderated by: Phil Bennett, AGA

Presentations and comments will focus on the NPRM's proposed requirements to allow operators to make applications to either PHMSA or its state regulator for deviations from required periodic inspections, as noted in 192.1017.

1) Jim Anderson, PHMSA
2) Phil Bennett, AGA
3) Art Shapiro, National Grid
4) Phil Sher, Connecticut Dept of Utility Control

4:00 pm GPTC Comments - Glen Armstrong, EN Engineering

4:10 pm Summary of Meeting