(7) *Report Results* (§ 192.1007(g))—Requires operators to report their performance results to PHMSA and the applicable State agency through annual reports (required by § 191.11).

The first step in developing a robust DIMP plan, as required in § 192.1007(a), is for operators to have knowledge of their gas distribution system. PHMSA has clarified through enforcement guidance that this knowledge should include, but is not limited to, the following characteristics: location, material composition, piping sizes, joining methods, construction methods, date of installation, soil conditions (where appropriate), operating and design pressures, operating history, operating performance data, condition of system, and any other characteristics noted by operators as important to understanding their system. This information may be obtained from sources including system maps, construction records, work management system, geographic information systems (GIS), corrosion records, and personnel who have knowledge of the system (subject matter experts).[35] This step also requires operators to identify missing data and to develop a plan to collect relevant information as part of their normal pipeline activities over time.

The second step in developing and implementing a DIMP plan, as required in § 192.1007(b), is for operators to use the information they have gathered in compliance with § 192.1007(a) to identify threats to the integrity of their gas distribution systems. Section 192.1007(b) currently requires that operators consider eight broad categories of threats. These threats are corrosion (including atmospheric corrosion), natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other issues that could threaten the integrity of the pipeline.[36] Operators must consider reasonably available information to identify existing and potential threats. Sources of data may include incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience (see § 192.1007(b)).

Section 192.1007(b) requires operators to consider certain categories of threats and consider reasonably available information to identify other existing and potential threats not specifically listed. PHMSA has clarified through guidance that operators should use sources of information such as past O&M procedures, abnormal operating events, purchase orders, material lists from old field orders or standards, and information from industry sources (*e.g.,* plastic pipe database committee (PPDC),[37] NTSB accident reports, or PHMSA advisory bulletins) to help identify threats.[38] PHMSA identified potential threats that include, but are not limited to, non-leak events such as near misses, overpressurizations, and material and appurtenance failures. Even though certain potential threats may not have caused system integrity issues on an operator's particular system in the past, the fact that known industry or systemic risks exist requires operators to account for the threat in their DIMP. Further, operators should not eliminate any existing or potential threat to a system without an adequate basis for doing so.[39] PHMSA reiterated through guidance material that operators should consider environmental conditions that may be conducive to threats developing over time (*e.g.,* atmospheric corrosion, hurricanes, flooding, excavation damage, or materials with known integrity issues), so that operators do not eliminate potential threats without proper consideration.[40] Prior to excluding a potential threat, operators should perform an analysis of their records to ensure that the pipeline has not experienced the threat to date.[41]

PHMSA clarified through enforcement guidance that to exclude a threat from consideration, an operator should document the basis for that conclusion and should not exclude a threat based on the unavailability of information to support the existence of such a threat.[42] Where data is missing or insufficient, an operator should use a conservative assumption in the risk assessment. Operators must maintain records that identify how they use unsubstantiated data so that operators and regulators can consider the impact on the variability and accuracy of risk analysis results.[43]

The third step in developing and implementing a DIMP plan, as required in § 192.1007(c), is to evaluate and rank risk. Risk is the likelihood of an event occurring multiplied by the consequence of that event. An event that is highly likely and has significant public safety or environmental consequences constitutes an event of greatest concern, while an unlikely event that has minimal consequences may not justify any particular precautions. On the other hand, an unlikely event that could have very high consequences may justify special precautions. Incidents on gas distribution systems are generally low-likelihood, but high-consequence, events.

Risk analysis is an ongoing process of understanding the risk each identified threat presents to a pipeline. Operators use the threats identified in § 192.1007(b) and any knowledge gained when complying with § 192.1007(a) to evaluate the risks associated with their pipelines. Operators then must rank the risks to determine their relative importance. PHMSA has recommended that operators prioritize and address the risks of greatest concern first.[44]

The fourth step in developing and implementing a DIMP plan, as required in § 192.1007(d), is for operators to determine and implement measures designed to reduce the risks from failure of their gas distribution pipelines. These measures include having an effective leak management program (unless all leaks are repaired when found).[45] PHMSA's enforcement guidance specifies that the process for identifying risk reduction measures should be based on identified threats.[46] Operators

[35] PHMSA, ''Gas Distribution Pipeline Integrity Management Enforcement Guidance'' at 19–23 (Dec. 7, 2015), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/DIMP_Enforcement_Guidance_12_7_2015.pdf* (''DIMP Guidance'').

[36] PHMSA, ''F 7100.1–1, Annual Report: Gas Distribution System'' (May 2021), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2021-05/Current_GD_Annual_Report_Form_PHMSA%20F%207100.1-1_CY%202021%20and%20Beyond.pdf.*

[37] The Plastic Pipe Database Committee, composed of representatives of the American Gas Association (AGA), American Public Gas Association (APGA), Plastics Pipe Institute (PPI), National Association of Regulatory Utility Commissioners (NARUC), NAPSR, NTSB, and PHMSA, coordinates the creation and maintenance of a database to proactively monitor the performance of in-service plastic piping system failures and leaks with the objective of identifying possible performance issues.

[38] PHMSA, ''Gas Distribution Pipeline Integrity Management Enforcement Guidance'' at 19–23 (Dec. 7, 2015), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/DIMP_Enforcement_Guidance_12_7_2015.pdf* (''DIMP Guidance'').

[39] DIMP Guidance at 18–19.

[40] DIMP Guidance at 19.

[41] DIMP Guidance at 19.

[42] DIMP Guidance at 18–19.

[43] DIMP Guidance at 19, 58. Section 192.1011 requires that operators must maintain records demonstrating compliance with the requirements of this subpart for at least 10 years. The records must include copies of superseded integrity management plans developed under this subpart.

[44] DIMP Guidance at 22, 61.

[45] PHMSA notes that it recently proposed in a separate rulemaking a number of revisions to its prescriptive part 192 leak detection requirements that would *(inter alia)* require gas distribution to adopt advanced leak detection programs based on commercially available, advanced leak detection equipment. *See* ''Gas Pipeline Leak Detection and Repair,'' 88 FR 31890 (May 18, 2023).

[46] DIMP Guidance at 28.

should promptly identify the need for risk reduction measures if a new risk is identified.

Overall, DIMP requirements direct operators to identify conditions that can result in hazardous leaks or other unintended consequences and take actions to reduce the likelihood of the occurrence of a hazardous condition and the consequences of a resulting failure. It is critical for operators to identify threats that affect, or could potentially affect, a distribution pipeline to ensure that pipeline's integrity. Knowledge of applicable threats, whether actual or potential, allows operators to evaluate the safety risks they pose and to rank those risks, allowing the operator to apply safety resources where they will be most effective. For the most effective results, operators should break down these broad threat categories into more specific threats. An operator must use the knowledge of their system gained as a result of complying with § 192.1007(a), combined with the threats identified pursuant to § 192.1007(b), to perform a risk analysis to evaluate the likelihood and consequences of failures for those threats described in § 192.1007(c) for which risk-reduction measures are then identified and implemented under § 192.1007(d). The more accurately and completely an operator characterizes their system, the more accurate the risk analysis results will be. This in turn should inform how an operator allocates resources to mitigate the risks associated with its system.

Pipeline incidents since the promulgation of the DIMP rules in 2011 have demonstrated that some distribution operators whose systems are subject to DIMP requirements are not adequately identifying (step 2), evaluating (step 3), or mitigating (step 4) the threats that are degrading and reducing the integrity of their pipeline systems. For example, NTSB's report on the Merrimack Valley incident found that, by at least September 2015, CMA employees knew of overpressure dangers associated with maintenance on belowground control lines for low-pressure system regulator stations: a faulty, damaged, or unaccounted for control line could lead to overpressurization, resulting in fires and explosions in a populated area.[47] In September 2015, NiSource and CMA internally disseminated Operational Notice (ON) 15–05, titled ''Below Grade Regulator Control Lines: Caution When Excavating Near Regulator Stations or Regulator Buildings.''[48] The impetus for ON 15–05 was a ''near-miss'' experience involving another NiSource company outside of Massachusetts where a construction crew that was excavating to repair a gas leak near a regulator station came close to hitting a control line and was unaware of its purpose and importance. The NTSB's report concludes that even though NiSource had historically identified overpressurization as a threat in at least some of its internal procedures, NiSource had nevertheless failed to undertake a systemic evaluation (*e.g.,* a failure modes and effects analysis) of the risks associated with that threat and the mitigating actions needed to manage those risks.[49]

More robust risk management was also needed in the planning of the South Union Street project, particularly with respect to the threat of overpressurization. NTSB concluded that NiSource's engineering package for that construction project failed to identify, and control for the vulnerability of its system to, a common mode of failure during the construction project that could result in an overpressurization. After the incident in the Merrimack Valley, NiSource worked to improve its risk management processes and installed automatic pressure-control equipment.[50] Therefore, the NTSB concluded that NiSource's engineering risk management processes were deficient.

Subsequent to the Merrimack Valley incident, 49 U.S.C. 60109(e)(7) was amended to require PHMSA to add more specificity to the DIMP requirements to ensure that operators consider specific threats to their systems. Specifically, PHMSA must update its regulations to ensure DIMP plans for distribution operators include an evaluation of certain risks, such as those posed by cast iron pipes and mains and low-pressure distribution systems, as well as the possibility of future accidents, to better account for high-consequence but low-probability events. Distribution operators must make their updated DIMP plans available to PHMSA or the relevant State regulatory agency two years after any final rule in this proceeding is issued and every 5 years thereafter, as well as following any significant change to an operator's DIMP plan or distribution system.[51]

Another recent incident that illustrates operator failure to adequately identify, evaluate, and rank risk is a series of leaks and explosions that occurred on a gas distribution system operated by Atmos Energy Corporation between February 21, 2018, and February 23, 2018, in Dallas, TX. The NTSB investigated the February 2018 incident.[52] As specified by the NTSB, although Atmos' DIMP plan was consistent with the currently applicable minimum requirements, their plan did not adequately address the inherent risks of its 71-year-old system. In addressing the likelihood of failure, the age of a pipe is generally recognized as an important performance factor.[53] Currently, PHMSA's regulations do not explicitly require gas distribution operators to consider the age of their pipelines under a DIMP. Instead, PHMSA's regulations in § 192.1007(c) state that ''[a]n operator may subdivide its pipeline into regions with similar characteristics (*e.g.,* contiguous areas within a distribution pipeline consisting of mains, services and other appurtenances; areas with common materials or environmental factors), and for which similar actions likely would be effective in reducing risk.'' Similar to what is described in PHMSA's regulations, Atmos grouped its assets into failure families based on asset attributes, such as material and coating. This method of evaluating the risks proved to be inadequate, given the high number of leaks observed that were due to the degradation of their pipelines over time.

Following the Atmos incident, NTSB issued recommendation P–21–2 to PHMSA.[54] This recommendation requires PHMSA to evaluate industry's implementation of DIMP requirements and to develop updated guidance for improving the effectiveness of operator DIMP plans. The recommendation goes on to say that the evaluation should ''specifically consider factors that increase the likelihood of failure such as age, increase the overall risk (including factors that simultaneously increase the likelihood and consequence of failure), and limit the effectiveness of leak management programs.''

[47] NTSB/PAR–19/02 at 18.

[48] NTSB/PAR–19/02 at 59–61.

[49] NTSB/PAR–19/02 at 40.

[50] NTSB/PAR–19/02 at 43.

[51] This provision also requires that operators make their current DIMP plans, emergency response plans, and O&M manuals available to PHMSA or the relevant State regulatory agency no later than December 27, 2022, which PHMSA intends to continue to review as appropriate in the course of inspection. *See* 49 U.S.C. 60109(e)(7).

[52] NTSB, Accident Report PAR–21/01, ''Atmos Energy Corporation Natural Gas-Fueled Explosion: Dallas, Texas: February 23, 2018'' (Jan. 12, 2021), *https://www.ntsb.gov/investigations/AccidentReports/Reports/PAR2101.pdf.*

[53] NTSB/PAR–21/01 at 66.

[54] NTSB/PAR–21/01 at 72.

In this NPRM, PHMSA proposes to revise DIMP requirements so that operators of gas distribution systems will improve their identification of existing and potential threats to their pipelines' integrity, improve the accuracy of their risk analyses, and take meaningful, timely actions to remediate or mitigate the highest risks to their infrastructure. When developing the proposals in this NPRM, PHMSA considered applicable statutory mandates and the NTSB recommendations that followed the CMA and Atmos incidents. The proposals described in the paragraph's below apply to all gas distribution operators, including individual service lines (also known as farm taps),[55] but excluding small LPG operators. PHMSA discusses the proposal to remove small LPG operators from DIMP in IV.A.7.

Based on its review of the evidence in the record, PHMSA expects the proposed amendments to the DIMP requirements would be reasonable, technically feasible, cost-effective, and practicable for gas distribution operators. As explained above, these operators are already required by PHMSA regulations to have DIMPs for (*inter alia*) identifying threats to pipeline integrity, evaluating the risks of those threats, and implementing mitigation measures to manage those risks. The NPRM's proposed amendments would clarify baseline expectations for implementation of those existing DIMP elements consistent with historical PHMSA guidance, industry operational experience and research, and statutory mandates in the PIPES Act of 2020, enacted after the Merrimack Valley incident. Said another way, the NPRM's proposed revisions are consistent with the actions reasonably prudent gas distribution operators would undertake in ordinary course in implementing current DIMP requirements on gas distribution pipelines transporting pressurized (natural, flammable, toxic, or corrosive) gasses that are typically in close proximity to, or within, population centers. Within the guardrails proposed herein, operators would retain the significant flexibility contemplated by current DIMP regulations for operators to design and implement their DIMPs in a manner appropriate for managing integrity risks on their specific pipeline facilities while minimizing compliance costs. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their DIMPs and manage any related compliance costs.

1. DIMP—Identify Threats (§ 192.1007(b))—Materials

a. Current Requirements—DIMP—Identify Threats—Materials

Section 192.1007(b) requires operators to consider the general threat category of ''material or welds,'' but the requirement does not state that operators must consider specific material types and how each type could pose a threat to the integrity of a system. PHMSA has clarified through enforcement guidance that operators should consider subcategories of ''material'' threats to better categorize their pipelines by age or specific pipe type (such as bare steel, cast iron, wrought iron, and plastic piping) to focus on the root cause of potential failures.[56] PHMSA has also issued advisory bulletins alerting operators of threats related to specific material types, including cast iron (ADB–2012–05) and plastic piping (ADB–07–01 and ADB–2012–03).[57] PHMSA's annual report form, PHMSA F 7100.1–1 (see 49 CFR 191.11), also requires operators to identify specific subtypes of materials and the pipeline mileage of each.

b. Need for Change—DIMP—Identify Threats—Materials

Different piping materials could pose different threats to gas distribution systems and should be identified prior to conducting a risk analysis of those threats. All things equal, pipelines that are made of certain materials, like cast iron, wrought iron, bare steel, unprotected steel, and certain plastic pipelines, are more susceptible to leaks and other pipeline integrity issues. In particular, cast-iron pipe was the subject of an advisory bulletin (ADB–2012–05) that reiterated two alert notices previously issued by PHMSA that addressed the continued use of cast- and wrought-iron pipe in gas distribution pipeline systems and reminded owners and operators and State pipeline safety representatives of the need to maintain an effective cast-iron management program.[58] Similar to cast- and wrought-iron piping, steel pipelines without corrosion protection coating—also known as bare-steel or unprotected pipelines—are made of a material that could be a threat to a gas distribution system, as that material is more susceptible to corrosion than coated steel.

Certain vintages and types of plastic piping are also known throughout the industry to present acute threats to pipeline integrity. For example, susceptibility to premature brittle-like cracking of certain Aldyl ''A'' pipe, along with other vintages and manufacturers' products, is a well-documented problem in the industry and the subject of the advisory bulletin ADB–07–02. In this advisory bulletin, PHMSA recommended that operators consider the threat of brittle-like cracking applicable to any Aldyl ''A'' pipe in service (under the general category of ''material''), regardless of whether the threat had resulted in leakage to date. Similarly, PHMSA also alerted operators to the risks of material degradation on Driscopipe8000 (Driscopipe Series 8000 high-density poly-ethylene (HDPE)) pipe in Arizona and Nevada in ADB–2012–03.

While many of these pipelines have been taken out of service, some of them continue to operate today. As discussed earlier, the Merrimack Valley incident involved the replacement of cast-iron and bare-steel pipelines with modern plastic piping. This was part of CMA's pipeline replacement program, which called for the replacement of leak-prone low-pressure cast iron pipelines (both mains and services) with modern plastic pipe. Many operators are also engaged in pipeline replacement projects in response to PHMSA's Action Plan; managing the reduction in cast- and wrought-iron inventory has been a priority and in progress for many years.

Following the Merrimack Valley incident, PHMSA was required by

[55] An individual gas service line directly connected to a gas transmission, production, or gathering pipeline is commonly referred to as a ''farm tap.'' Individual service lines have the option of following either § 192.740, for service lines that are *not* operated as part of a distribution system, or DIMP (as detailed in § 192.1003(b)) for any portion of the individual service line that is classified as a service line. This rule proposed no change to this scope. The proposals apply to those individual service lines (aka farm taps) that apply DIMP.

[56] DIMP Guidance at 20.

[57] ''Pipeline Safety: Cast Iron Pipe (Supplementary Advisory Bulletin),'' ADB–2012–05, 77 FR 17119 (Mar. 23, 2012); ''Pipeline Safety: Notice to Operators of Driscopipe® 8000 High Density Polyethylene Pipe of the Potential for Material Degradation,'' ADB–2012–03, 77 FR 13387 (Mar. 6, 2012); ''Updated Notification of Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe,'' ADB–07–02, 72 FR 51301 (Sept. 6, 2007).

[58] RSPA, ALN–92–02 (June 26, 1992); RSPA, ALN–91–02 (Oct. 11, 1991).

statute to ensure that operators evaluate the risk of the presence of cast iron in their DIMP plans. While only cast-iron was specifically identified as a material warranting explicit mention in DIMP regulations,[59] PHMSA understands that the Merrimack Valley incident (which occurred on a pipeline with both cast iron and bare steel) underscores that other types of high-risk materials on gas distribution systems warrant similar treatment. Although operators are already identifying what specific piping materials are on their system,[60] and § 192.1007(b) requires operators to actively monitor and consider the presence of piping material with known issues under the general threat category of ''material or welds,'' PHMSA believes that clarifying this practice in the DIMP regulations would ensure that as operators implement their DIMP plans, they consider the risks associated with the presence of these leak-prone materials, as required by the risk analysis in § 192.1007(c).

c. Proposal To Amend § 192.1007(b)—DIMP—Identify Threats—Materials

PHMSA proposes to revise § 192.1007(b) to clarify that operators must identify the threats posed by specific material types in their pipeline system, such as cast iron, wrought iron, bare steel, and historic plastic pipe with known issues. PHMSA expects that, in determining whether a plastic pipe material is a ''historic plastic with known issues'' representing a threat to pipeline integrity, operators should consider PHMSA and State regulatory actions and industry technical resources identifying systemic integrity issues on plastic pipe made from particular materials manufactured at particular times or by particular companies, or fabricated and installed pursuant to particular processes. As noted above, PHMSA issues advisory bulletins cautioning operators regarding the susceptibility of certain historic plastic pipelines to systemic integrity issues. Similarly, State pipeline safety regulatory actions, PHMSA pipeline failure investigation reports, and NTSB findings can inform operator determinations whether historic plastic pipe is at a high-risk loss of integrity. Industry efforts and resources are another resource for operators in determining whether historic plastic pipe has known issues. For example, the PPDC publishes periodic status reports of data submitted by program participants that incorporates information regarding investigations of materials of concern or potential concern.[61] PHMSA expects that these and other authoritative resources—coupled with an operator's own design expertise and operational and maintenance history—would be adequate for a reasonably prudent operator to determine whether the particular plastic pipe in its distribution system is a historic plastic with known issues. PHMSA further invites comment on whether, within a final rule in this proceeding, there would be value (in addition to being cost-effective, practicable, and technically feasible) in either explicitly listing (within subpart P or periodically-issued implementing guidance) historic plastics prone to leakage, or deleting the scope qualification ''historic'' from proposed regulatory text.

Once the threats are identified under § 192.1007(b), operators are also required to evaluate these risks under § 192.1007(c) and to ensure that risk reduction measures are identified and implemented under § 192.1007(d).

2. DIMP—Identify Threats (§ 192.1007(b))—Overpressurization

a. Current Requirements—DIMP—Identify Threats—Overpressurization

Section 192.1007(b) does not explicitly require operators to consider the threat of overpressurization as a threat under their DIMP plans. Instead, § 192.1007(b) requires operators to consider the general threat category of ''incorrect operations'' or ''other issues that could threaten the integrity of [a] pipeline'' and requires operators to consider whether those threats exist on their systems. However, overpressurization is a potential threat to gas distribution systems. PHMSA has stated through previous enforcement guidance and an advisory bulletin (ADB–2020–02) that overpressurization is a threat, especially for low-pressure gas distribution systems, and recommended that operators identify overpressurization as a threat in their DIMP plans. Further, § 192.195 provides design requirements for the protection against accidental overpressurization, including additional requirements for distribution systems.

b. Need for Change—DIMP—Identify Threats—Overpressurization

The threat of overpressurization, particularly on low-pressure gas distribution systems, is a threat that PHMSA expects operators to consider in their DIMP plans. PHMSA considers the threat of overpressurization to fall under the threat categories of both ''incorrect operations'' and ''other issues that could threaten the integrity of [a] pipeline'' in § 192.1007(b). In enforcement guidance, PHMSA lists ''overpressurization events'' as an example of potential threats operators could experience on their pipelines.[62] PHMSA also requires operators to have sufficient knowledge of their systems, per § 192.1007(a), to determine if overpressurization is a threat on their specific systems and to develop and implement measures to mitigate the consequences of a potential overpressurization. As discussed earlier, PHMSA also issued an advisory bulletin (ADB–2020–02) alerting operators of low-pressure gas distribution systems of the increased risk of overpressurization on those systems and recommended that operators consider the threat of overpressurization in their DIMP plans.

Recent incidents underscore the importance of operators adequately identifying the risk of overpressurization on distribution systems. Prior to the Merrimack Valley incident on September 13, 2018, the operator experienced four other overpressurizations and one ''near-miss'' within its network of distribution systems.[63]

On March 1, 2004, a system overpressurized when debris lodged at the seat of the bypass valve in Lynchburg, VA.

On February 28, 2012, an operator error during an inspection resulted in accidental overpressurization in Wellston, OH. 300 customers were without service for 14 hours.

On March 21, 2013, a segment of a pipe with an MAOP of 1 psig was pressurized at over 2 psig in Pittsburgh, PA. A work crew, under the direction of

[59] PHMSA notes, however, the threats to pipeline integrity posed by other materials. Specifically, 49 U.S.C. 60108 (Section 114 of PIPES Act of 2020) imposes a self-executing mandate on gas transmission, distribution, and part-192 regulated gas gathering pipeline operators to update their inspection and maintenance procedures to provide for replacement or remediation of pipelines ''known to leak based on their material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues) . . . .'' PHMSA is considering within a separate rulemaking (under RIN 2137–AF54) whether to incorporate that self-executing statutory mandate within its 49 CFR part 192 regulations. *See* ''Gas Pipeline Leak Detection and Repair,'' 88 FR 31890 (May 18, 2023). PHMSA submits that this NPRM's amendments to DIMP requirements at subpart P would complement any revisions to prescriptive regulations elsewhere in 49 CFR part 192 that PHMSA may adopt in that parallel rulemaking.

[60] Operators are already subcategorizing their pipeline segments by material type (*i.e.,* cast iron, wrought iron, bare steel, and certain plastics with known issues) in their annual report form, PHMSA F 7100.1–1. *See supra* note 36.

[61] AGA, ''Plastic Pipe Data Collection Initiative'', *https://www.aga.org/natural-gas/safety/promoting-safety/plastic-pipe-data-collection-initiative/* (last visited March 10, 2023).

[62] DIMP Guidance at 19, 59.

[63] NTSB/PAR–19/02 at 25.

the local NiSource subsidiary, was making a tie-in and failed to monitor the pressure and flow of the existing low-pressure natural gas distribution system during the tie-in process.

On August 11, 2014, a local NiSource crew in Frankfort, KY, was excavating to repair a leak located on the outside of a regulator station building. The crew uncovered and narrowly missed hitting the 1-inch control line and tap located on the 8-inch outlet pipeline. The crew was unaware of the purpose of the 1-inch line and called local measurement and regulation (M&R) personnel. The M&R personnel advised the crew of the purpose of a control line and what would have happened had the line been broken. As discussed earlier, in 2015 NiSource issued ON 15–05 in response to this near miss. ON 15–05 required that M&R personnel be consulted on all future excavation work done within 25 feet of a regulator station with sensing lines, other communications and/or electric lines critical to the operation of the regulator station, or buried odorant lines. On September 13, 2018 (the date of the Merrimack Valley incident), however, CMA did not follow those procedures or implement any preventive or mitigative measures as they should have if they were correctly following DIMP requirements.

On January 13, 2018, during the investigation of a service complaint, an overpressurization was discovered on a natural gas distribution system in Longmeadow, MA. The cause was associated with debris accumulation on both the worker and monitor regulator seats at a regulator station. Once the debris was removed, the pressure returned to normal. This event illustrates that, in some cases, an overpressurization can occur that does not cause a catastrophic failure of the entire system, but if the operator takes timely, mitigative action, the system can safely return to normal. Operators know debris accumulation at regulator stations can cause an overpressurization and can plan routine maintenance of regulator stations to remove debris or install a device to prevent the debris from reaching the regulator station. However, an operator must first recognize overpressurization as a threat to ensure that they allocate resources to address this threat.

While overpressurization is a threat that PHMSA expects operators to consider in their DIMP plans, the pipeline safety regulations do not explicitly state that operators must identify and evaluate the threat of overpressurization in their DIMP plans. Following the Merrimack Valley incident on September 13, 2018, PHMSA was required by law to ensure that operators evaluate the risk of overpressurization in their DIMP plans. PHMSA therefore proposes to amend § 192.1007(b) to explicitly require operators to identify overpressurization as a threat to low-pressure distribution systems. The proposal is intended to ensure that operators consider this risk on their system as required by the risk analysis in § 192.1007(c) and identify risk reduction measures in accordance with § 192.1007(d).

c. Proposal To Amend § 192.1007(b)—DIMP—Identify Threats—Overpressurization on Low-Systems

PHMSA proposes to amend § 192.1007(b) to create a new threat category of ''overpressurization on low-pressure systems.'' This change would ensure that consideration of risks under the DIMP regulations explicitly includes overpressurization of a low-pressure system as a threat. Once identified as a threat under § 192.1007(b), operators would also have to evaluate the likelihood and the potential consequences of such a failure, as required in § 192.1007(c), and ensure risk-reduction measures are identified and implemented under § 192.1007(d). PHMSA discusses the actions operators must take to implement § 192.1007(c) and § 192.1007(d) in subsection IV.A.5 and 6 of this preamble.

3. DIMP—Identify Threats (§ 192.1007(b))—Natural Forces

a. Current Requirements—DIMP—Identify Threats—Natural Forces Including Extreme Weather and Geohazards

Section 192.1007(b) requires operators to consider the general threat category of ''natural forces,'' but the requirement does not explicitly state what natural forces could pose a threat to the integrity of the system. Natural force damage occurs as a result of naturally occurring events, including: (1) earthquakes and landslides; (2) heavy rains and flooding; (3) high winds, tornadoes, or hurricanes; (4) temperature extremes; and (5) lightning.[64] Further, PHMSA has issued advisory bulletins alerting operators to threats related to natural forces such as land movement (*i.e.,* geological hazards or ''geohazards'' [65]) (ADB–2022–01 and ADB–2019–02), severe flooding (ADB–2019–01), snow and ice build-up (ADB–2016–03), and extreme temperatures (ADB–2012–03).[66]

b. Need for Change—DIMP—Identify Threats—Natural Forces Including Extreme Weather and Geohazards

A distribution pipeline system operates in a discrete environment due to the limited geographic scope of each individual system. The environment in which a system operates significantly affects the threats to pipeline integrity that it faces. Factors such as weather (dry or wet, hot or subject to freezing) can significantly shape the threats affecting individual distribution operators and the actions necessary to address those threats. Major climate trends, such as elevated average surface temperatures, more intense storm events, and flooding, can, independently and in combination, affect the reliability and integrity of the United States' gas distribution infrastructure. As climate change has made extreme weather more common, it is harder to categorize what types of environmental factors facing distribution pipelines are ''normal'' based on geography and historical averages alone.

While freezing weather once seemed like a problem reserved for northern regions of the United States, southern regions are also experiencing unseasonable and extremely cold weather. For example, in February of 2021, Texas experienced a winter storm that brought some of the coldest temperatures in its history.[67] Extremely cold weather can cause thermal contraction stress or fractures of pipelines due to the expansion of moisture trapped inside components. In addition, safety relief devices can malfunction due to icing or freezing.

Low temperatures and the accumulation of snow and ice also increases the potential for physical

[64] PHMSA, ''Fact Sheet: Natural Force Damage'' (July 23, 2014), *https://primis.phmsa.dot.gov/comm/FactSheets/FSNaturalForce.htm.*

[65] PHMSA also interprets natural hazards to include geohazards.

[66] ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,'' ADB–2022–01, 87 FR 33576 (June 2, 2022); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards,'' ADB–2019–02, 84 FR 18919 (May 2, 2019); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,'' ADB–2019–01, 84 FR 14715 (Apr. 11, 2019); ''Pipeline Safety: Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems,'' ADB–2016–03, 81 FR 7412 (Feb. 11, 2016); ''Notice to Operators of Driscopipe 8000 High Density Polyethylene Pipe of the Potential for Material Degradation,''ADB–2012–03, 77 FR 13387 (Mar. 6, 2012). PHMSA notes that many of those advisory bulletins identify resources maintained by other Federal agencies that can assist pipeline operators in identifying and evaluating integrity threats to their pipelines.

[67] On February 16, 2021, Dallas, TX recorded temperatures as low as −2 °F.

damage to meters and regulators and other aboveground pipeline facilities and components. For example, ice forming on regulators or pressure relief devices can cause them to malfunction or stop working completely.[68] Exposed piping at metering and pressure regulating stations, at service regulators, and at propane tanks are at the greatest risk. On February 11, 2016, PHMSA issued advisory bulletin ADB–2016–03 alerting operators to the dangers of abnormal snow and ice buildup on gas distribution systems. PHMSA has issued four other advisory bulletins since 1993 on this same issue.[69]

Natural forces such as severe flooding, river scour, and river channel migration can also adversely affect the safe operation of a pipeline. These incidents can damage a pipeline as a result of additional stresses imposed on the pipe by undermining underlying support soils, exposing the pipeline to lateral water forces and impact from waterborne debris. Additionally, the proper function of valves, regulators, relief sets, pressure sensors, and other facilities normally above ground or above water can be jeopardized when covered by water. PHMSA has issued several advisory bulletins alerting operators to the dangers severe flooding, river scour, and river channel migration can impose on a pipeline, most recently in 2019 through ADB–2019–01 and again in 2022 through ADB–2022–01.[70] Sometimes flooding is seasonal and predictable; however, the Intergovernmental Panel on Climate Change (IPCC) predicts increases in the frequency and intensity of heavy precipitation, which will give rise to increased risk of flooding.[71] In some areas, climate change means higher average precipitation,[72] resulting in water saturation that inhibits the ability of soil to absorb extreme precipitation events. Climate change may, however, result in drought for other parts of the United States,[73] as lower average annual precipitation rates result in lower soil moisture—and therefore, less ability to absorb extreme precipitation events. Also, rainfall during the four wettest days of the year has increased about 35 percent, and the amount of water flowing in most streams during the worst flood of the year has increased by more than 20 percent.[74] For parts of the United States, spring rainfall and average precipitation are likely to increase and severe rainstorms are likely to intensify during the next century.[75] Each of these factors will tend to further increase the risk of flooding—operators must assess how this may impact the integrity of their pipelines.

Extremely high temperatures can also pose integrity threats to certain materials. In March 2012, PHMSA issued advisory bulletin ADB–2012–03 regarding the potential for degradation of Driscopipe8000 pipes, which were produced from 1979 through 1997.[76] All reported occurrences of in-service degradation and leaks related to Driscopipe8000 pipes were installed in the desert region of the southwestern United States, particularly in the Mojave Desert region in Arizona, California, and Nevada. The ambient temperatures in the southwestern United States are very high (typically over 100 degrees Fahrenheit) and may contribute to issues for plastic piping. Driscopipe Series 7000 and 8000 HDPE pipe exposed to prolonged elevated temperatures may degrade as a result of thermal oxidation. One of the largest producers of polyethylene piping products in North America, has noted that ''the mechanism for this oxidation appears to be the depletion of the thermal stabilizer, which has been shown to occur over time in high ambient temperature conditions.''[77] PHMSA has reminded operators through ADB–2012–03 that they should monitor the performance of their plastic piping.

Following the Merrimack Valley incident, PHMSA reviewed its current DIMP regulations for areas where additional clarification could improve the safety of gas distribution pipelines. As climate change increases the frequency of extreme weather events and natural forces that can impact the integrity of pipelines, PHMSA proposes to add clarity to the DIMP regulations to ensure that operators are considering these threats when evaluating risks. Operators would, therefore, need to consider and take appropriate action to address the impacts of extreme weather as a threat, regardless of whether they had experienced such events in their pipelines' history, while still recognizing regional differences. PHMSA expects operators to continue evaluating reasonably available information regarding changing operating environments (*i.e.,* climate) and the regional impacts of extreme weather on their pipeline.

c. PHMSA's Proposal To Amend § 192.1007(b)—DIMP—Identify Threats—Natural Forces Including Extreme Weather and Geohazards

PHMSA proposes to amend § 192.1007(b) to specify that operators must include the threat of extreme weather and geohazards as subcategories under the threat category of ''natural forces.'' This amendment would ensure that operators consider the threat of extreme weather under the DIMP regulations. Once identified as a threat under § 192.1007(b), operators would be required to consider how potential extreme weather events could increase the likelihood of failure. They would also need to consider the potential consequences of such a failure, as required in § 192.1007(c), and ensure that they identify risk-reduction measures and implement them under § 192.1007(d). PHMSA expects that operators would not limit their

[68] Regulators must be adequately protected from obstructions such as dirt, insects, and ice. If the vent on a regulator becomes completely obstructed, then the regulator can either shut off the flow of gas to a customer or increase the pressure to the upstream pressure, causing possible failures.

[69] ''Pipeline Safety: Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems,'' ADB–11–02, 76 FR 7238 (Feb. 9, 2011); ''Pipeline Safety: Dangers of Abnormal Snow and Ice Build-Up on Gas Distribution Systems,'' ADB–08–03, 73 FR 12796 (Mar. 10, 2008); ''Potential Damage to Pipelines by Impact of Snowfall, and Actions Taken by Homeowners and Others to Protect Gas Systems from Abnormal Snow Build-up,'' ADB–97–01 (Jan. 24, 1997); ''Pipeline Safety Advisory Bulletin; Snow Accumulation on Gas Pipeline Facilities,'' ADB–93–01, 58 FR 7034 (Feb. 3, 1993).

[70] *See, e.g.,* ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,'' ADB–2016–01, 81 FR 2943 (Jan. 19, 2016); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes,'' ADB–2015–02, 80 FR 36042 (June 23, 2015); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration,'' ADB–2015–01, 80 FR 19114 (Apr. 9, 2015); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding,'' ADB–2013–02, 78 FR 41991 (July 12, 2013); ''Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Flooding,'' ADB–11–04, 76 FR 44985 (July 27, 2011).

[71] IPCC, Seneviratne, S.I., N. Nicholls et al., ''Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation'' at 113 (2012), *https://www.ipcc.ch/site/assets/uploads/2018/03/SREX-Chap3_FINAL-1.pdf.*

[72] U.S. Envtl. Prot. Agency, ''What Climate Change Means for Missouri'', EPA 430–F–16–027, at 1 (Aug. 2016), *https://19january2017snapshot.epa.gov/sites/production/files/2016-09/documents/climate-change-mo.pdf* (noting that over the last half century, average annual precipitation in most of the Midwest has increased by 5 to 10 percent).

[73] *See* A. Park Williams et al., ''Rapid Intensification of the Emerging Southwestern North American Megadrought in 2020–2021,'' 12 Nature Climate Change 232–234 (2022).

[74] U.S. Envtl. Prot. Agency, ''What Climate Change Means for Missouri,'' at 1.

[75] U.S. Envtl. Prot. Agency, ''Climate Impacts in the Midwest,'' Climate Change Impacts, *https://climatechange.chicago.gov/climate-impacts/climate-impacts-midwest* (last visited Feb. 25, 2023).

[76] 77 FR at 13388.

[77] Performance Pipe, ''Driscopipe® 8000 Pipe Degradation in High Temperature Applications'' *https://www.cpchem.com/sites/default/files/2020-05/DriscopipeDegradation.pdf* (last visited Mar. 1, 2023).

consideration of the threat of extreme weather solely on past normal weather patterns but would also consider any anticipated increases in extreme weather conditions and fluctuations. This proposed requirement would improve safety by ensuring that operators address the impacts of climate change and protect the reliability and integrity of their pipeline systems, even if operators have yet to experience these issues on their systems.

4. DIMP—Identify Threats (§ 192.1007(b))—Age of the System, Pipe, and Components

a. Current Requirements—DIMP—Identify Threats—Age of the System, Pipe, and Components

Section 192.1007(b) includes a generic threat category of ‘‘other issues that could threaten the integrity of [a] pipeline,’’ which operators should use to identify threats that do not fit into the other threat categories. When performing their risk analysis, § 192.1007(c) states that operators ‘‘may subdivide [their] pipeline into regions with similar characteristics.’’ PHMSA has observed operators using age as a method of subdividing their pipeline segments when performing the risk analysis. Further, PHMSA’s annual report form, PHMSA F 7100.1–1, requires operators to identify the miles of pipeline by decade of installation. Section 192.1007(b) does not, however, specifically require that operators consider the age of a pipe or components when identifying threats to pipeline integrity.

b. Need for Change—DIMP—Identify Threats—Age of the System, Pipe, and Components

Over time, all pipeline systems are subject to time-dependent degradation processes threatening pipeline integrity. Pipelines made from ferrous materials (steel, wrought iron, cast iron, etc.) are all susceptible to oxidation corrosion over time. Plastic and composite materials used in pipelines are subject to photodegradation if exposed to sunlight. Joints, fittings, and welds connecting various pipeline components can be subject to dissimilar materials corrosion or chemical degradation of bonding agents and sealants. And the longer the timeline, the more any gas pipeline components are exposed to a variety of phenomena—*e.g.,* from internal mechanical stresses, changes in temperature, changes in external loads (including external force damage)—that threaten pipeline integrity, exacerbate existing material weaknesses, or accelerate time-dependent degradation processes.

Age can impact and potentially modify each of the threats an operator identifies in § 192.1007(b). The potential threat to pipeline integrity posed by age depends on the age of the pipeline components of which it is comprised. PHMSA understands the cumulative effect of those age-related threats to integrity across an entire pipeline are not merely the sum of age-related, component-specific threats; rather, those threats can magnify or exacerbate one another when integrated within a pipeline system. For example, one component’s failure due to time-dependent degradation processes can strain other components throughout the system (*e.g.,* by releasing corrosion products that can damage other, newer components within the system). PHMSA further notes that trending failure rates by age can be a useful tool for revealing degraded performance throughout a pipeline system.

Similarly, the overall age of the pipeline system can provide more opportunities for safety-critical gaps in material records. Poor recordkeeping with respect to a pipeline component dating from a certain time period may threaten not only pipeline integrity on that segment, but also other components of the same pipeline installed at a different time period.

Age can also be expressed in terms of vintage of pipes or components. Specific manufacturing techniques and materials used during certain periods of time can result in similar characteristics among pipes and components of a given vintage. The vintage of pipes or components can interact with other threats, including materials, equipment failures, or natural forces. For example, pipe installed earlier than 1950 has disproportionately high susceptibility to problems from cold weather and freezing, which could interact with the threat of natural forces. The greater susceptibility of pre-1950 pipe is thought to be due to inferior low-temperature ductility of the steels of the era and the methods used to join pipe at the time (such as electric arc welds, acetylene welds, couplings, and threaded collars).[78] Additionally, as described in section IV.A.1 (materials), some of the early plastic piping products manufactured from the 1960s and into the early 1980s are more susceptible to brittle-like cracking (also known as slow-crack growth) than newer materials.[79]

Even though time-dependent degradation processes are widely understood threats to the integrity of pipeline systems, as discussed earlier, § 192.1007(b) does not specifically state that operators must account for the age of the system, pipe, and components in identifying threats. Increasing failure rates have been observed in older gas distribution infrastructure that has certain attributes.[80] The increasing failure rate typically occurs toward the end of life and accelerates the rate by which the reliability decreases. This behavior is typically attributed to cumulative degradation that occurs in the system over its service period. Trending failure rates by system age can reveal degrading performance.

Recent incidents have illustrated that operators may be inadequately identifying and managing threats related to the age of components on their systems. For example, in its risk analysis, Atmos used a commercially available software that did not explicitly consider the age of the pipeline segments, instead grouping them into failure categories based on similar attributes, such as material and coating. Although such an approach may have been compliant with current regulations, this approach to risk analysis disregards how the age could contribute to failures. Following the 2018 Atmos incidents, the NTSB recommended that Gas Piping Technology Committee develop guidance and identify steps operators can take to ensure that their gas distribution IM programs appropriately consider threats that degrade a system over time.[81] By adopting such a practice, operators would recognize the full threat based on the impact of age and prioritize remediating or replacing segments of the pipe and components that pose more acute threats. PHMSA therefore proposes to revise § 192.1007(b) to explicitly identify age as a factor in addressing threats to integrity.

c. Proposal To Amend § 192.1007(b)—DIMP—Identify Threats—Age of the System, Pipe, and Components

PHMSA proposes to amend § 192.1007(b) to clarify that operators

[78] M.J. Rosenfeld, ‘‘Cold Weather Can Play Havoc On Natural Gas Systems’’ 242 Pipeline & Gas J. 1 (Jan. 2015), *https://pgjonline.com/magazine/2015/january-2015-vol-242-no-1/features/cold-weather-can-play-havoc-on-natural-gas-systems.*

[79] Brittle-like cracking failures occur under conditions of stress intensification. Stress intensification is more common in fittings and joints.

[80] PHMSA, ‘‘Pipeline Replacement Background’’ (Apr. 26, 2021), *https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/pipeline-replacement-background.*

[81] NTSB/PAR–21/01 at 82.

must, when identifying the threats on its distribution system, also consider the age of the system, piping, and components in identifying threats.[82] For example, once an operator identifies a time-dependent threat exists on their pipeline, such as corrosion, the operator would then consider how the age of the pipe, or the components, could influence the severity of the threat. All things equal, an older pipe or component exposed to the threat of corrosion could carry additional risk compared to newer pipe. Similarly, for time-independent threats, such as natural forces, the operator would consider how the age of the pipeline or components would expose the pipeline to multiple threats over its lifetime, a threat that may evolve or increase over time. PHMSA's proposal would ensure that the DIMP regulations explicitly account for how the age of the system, pipes, and components contribute to a pipeline's integrity degrading over time.

5. DIMP—Evaluate and Rank Risk (Section 192.1007(c))

a. Current Requirements—DIMP—Evaluate and Rank Risk

Section 192.1007(c) requires that operators evaluate and rank the risks associated with their distribution pipeline systems. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure. Operators may subdivide their distribution systems into regions (areas within a distribution system consisting of mains, services, and other appurtenances) that have similar characteristics and reasonably consistent risks, and for which similar actions would be effective in reducing risk.

Through enforcement guidance, PHMSA recommended that operators develop weighted factors for each threat specific to their system depending upon their unique operating environment.[83] PHMSA has further stressed that it may be inadequate for operators to conclude that a pipeline is not subject to any particular threat based solely on the fact that it has not experienced a pipeline failure attributed to the threat.[84] PHMSA has used enforcement guidance to clarify that if operators conclude that a particular threat is not applicable to sections of their pipeline, then operators should document the basis for drawing that conclusion.[85] This basis should consider the pipeline's failure history, design, manufacturing, construction, operation, and maintenance.

b. Need for Change—DIMP—Evaluate and Rank Risk

Recent incidents have demonstrated the importance of operators adequately evaluating and ranking risks on their systems and in their DIMP plans. For example, as demonstrated by the 2018 Merrimack Valley and other incidents investigated by the NTSB, some operators have not been adequately evaluating the risk of overpressurization, and thus not taking appropriate mitigating measures to account for those risks.[86] Overpressurization incidents—in particular on low-pressure gas distribution systems—merit mitigation because they have a high-consequence. As previously noted, CMA had knowledge of the risks of an overpressurization, updated their procedures, and still did not take appropriate action to mitigate the risks. Similarly, the Atmos incident in Texas demonstrated how operators can underestimate the risks associated with the presence of leak-prone materials.

PHMSA is required by law to ensure that operators' DIMP plans evaluate the presence and risks associated with cast iron piping and the threat of overpressurization on low-pressure gas distribution systems (49 U.S.C. 60109(e)(7)). PHMSA is also required to prohibit operators, when evaluating risks related to the operation of a low-pressure gas distribution system, from determining that there are no potential consequences associated with low-probability events unless that determination is supported by ''engineering analysis or operational knowledge.'' PHMSA must also ensure that operators of gas distribution systems consider factors other than past observed ''abnormal operating conditions''—as that term is defined at § 192.803—when ranking risks and identifying measures to mitigate those risks.

c. PHMSA's Proposal To Amend § 192.1007(c)—DIMP—Evaluate and Rank Risk

PHMSA proposes to redesignate the general requirements of § 192.1007(c) under a new paragraph (c)(1). These general requirements still require operators to consider the identified threats proposed in § 192.1007(b) as they evaluate and rank risks.

i. Certain Pipe Materials With Known Issues

PHMSA proposes to amend § 192.1007(c) by creating a new § 192.1007(c)(2) to specify that operators must evaluate the risks resulting from pipelines constructed with certain materials (including cast iron, bare steel, unprotected steel, wrought iron, and historic plastics with known issues) when such materials are present in their pipeline systems. Overall, these proposed requirements would improve safety by codifying in DIMP requirements some of the known, industry-wide threats if the materials that have exhibited these threats are present in the operator's systems, even if operators have not yet experienced any of these issues on their systems.

ii. Evaluate and Rank Risk: Low-Pressure Distribution Systems

PHMSA also proposes to amend § 192.1007(c) by creating a new § 192.1007(c)(3) applicable to low-pressure distribution systems. Consistent with the mandate in 49 U.S.C. 60109(e)(7), PHMSA proposes to require operators of low-pressure gas distribution systems to evaluate ''the risks that could lead to or result from the operation of a low-pressure distribution system at a pressure that makes the operation of any connected and properly adjusted low-pressure gas burning equipment unsafe.'' For the purposes of this NPRM, PHMSA determines that ''unsafe'' in this context means that gas flowing into the downstream equipment is at a pressure beyond the rated supply pressure specified by the manufacturer of that equipment. This amendment would ensure that operators are addressing the risks on their pipeline that could result in an overpressurization.

In evaluating the risks to low-pressure distribution systems, the mandate in 49 U.S.C. 60109(e)(7)(B) requires PHMSA to ensure that operators consider ''factors other than past observed abnormal operating conditions [. . .] in ranking risks.'' This includes any abnormal operating conditions (AOCs) that operators have experienced (*i.e.,* observed) on their system and any unobserved AOCs that could occur on their system (*i.e.,* an overpressurization on a low-pressure system), including any known industry threats, risks, or hazards, as identified by an operator from available sources (*e.g.,* PHMSA advisory bulletins, PHMSA incident and accident reports, PHMSA and NTSB accident reports, State pipeline safety regulatory actions, and operator knowledge sharing). PHMSA proposes

[82] *See* Am. Soc'y of Mech. Eng's, ANSI B31.8S–2004, ''Managing System Integrity of Gas Pipelines,'' at sec. 2 (Jan. 14, 2005).

[83] DIMP Guidance at 22.

[84] DIMP Guidance at 23.

[85] DIMP Guidance at 18, 57.

[86] NTSB/PAR–19/02 at 18–21, 39–40, 48.

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in § 192.1007(c)(3)(i) to require operators of low-pressure systems to evaluate risks to their systems in accordance with the mandate. This amendment would ensure that operators are reviewing their past observed operational performance to evaluate the risks on their systems. This amendment would also ensure that operators are considering risks even if they have yet to experience those risks on their systems. For example, if an operator has not experienced an overpressurization on its system, that operator must still consider the risks of an overpressurization on its system.

The mandate in 49 U.S.C. 60109(e)(7)(B) also states that operators may not determine that low probability events have no potential consequences without a supporting determination. PHMSA proposes integrating this mandate by adding a new paragraph § 192.1007(c)(3)(ii) that will direct operators to evaluate the potential consequences associated with low-probability events, unless a determination—supported and documented by an engineering analysis or other equivalent analysis incorporating operational knowledge—demonstrates that the event results in no potential consequences (and therefore no potential risk).

An engineering analysis would include documentation of the engineering principles used to calculate the flows, pressures, and other parameters of the piping and systems to calculate the actual downstream pressure. This engineering analysis would also include documentation of the methods used to determine that the system cannot fail and cause overpressurization, including any data and assumptions (including mitigation and control measures) utilized by the operator. This engineering analysis may necessarily include degrees of measurable operational knowledge regarding specific pipeline characteristics and evidence from that analysis combined with documentable known pipeline characteristics. An operator that determines there are no potential consequences from a low-probability event must document all these reasons as part of its ''engineering analysis'' submitted to PHMSA according to § 192.18 with sufficient detail as listed in § 192.1007(c)(3)(ii)(A)–(F).

Because the statute requires operators to make an affirmative determination that there are no potential consequences associated with low probability events and recognizing that some operators might not have fully considered the risk of low-probability events based solely on operational knowledge, PHMSA proposes that any operational knowledge relied upon must include with it a quantifiable assessment and support the operator's determination with a level of rigor equal to that of an engineering analysis. This operational knowledge could be included as part of the proposed regulatorily required ''engineering analysis, or an equivalent analysis,'' as used in § 192.1007(c)(3)(ii). For example, should an operator determine that a release of gas from the pipeline, such as a leak, has no potential consequences, the operator should include documentation demonstrating that many scenarios were considered (such as a leak with ignition or gas migration under nearby pavement) and that no potential consequences were identified in any of those potential scenarios. This amendment would ensure that operators do not dismiss material risks without a meaningful evidentiary basis, and PHMSA or pertinent State authorities would have the opportunity to review and consider the validity of the operator's determination when reviewing DIMP plans.

State regulatory authorities already review operators' DIMP plans during regular inspections. Because incorrectly determining that a potential threat has no consequences would have serious public safety impacts, however, PHMSA understands there is a compelling policy reason for an operator's determination that a low-frequency event entails zero risk be reviewed by those State regulatory authorities as well as PHMSA. Therefore, if operators choose to apply the proposed exception in § 192.1007(c)(3)(ii), they must notify PHMSA and the appropriate State Authority in accordance with § 192.18 within 30 days of making this determination that there are no potential consequences associated with the low-probability event. The notification must include information such as the date the determination was made (to ensure compliance with the proposed timeline), descriptions of the low-probability events being considered, and a description of the logic supporting the determination, including information from an engineering analysis or an equivalent analysis incorporating operational knowledge. Further, this notification should contain a description of any preventive and mitigative measures, including any measures considered but not taken, as determined through the engineering analysis or an equivalent analysis incorporating operational knowledge. The notification should also include a description of the low-pressure system, including, at a minimum, miles of pipe, number of customers, number of district regulators supplying the system, and other relevant information. In addition, operators must provide a written statement summarizing the documentation it evaluated and how the conclusion that there would be no potential consequences associated with the low-probability event was reached. This documentation could include the inspection and maintenance history of the pipeline segment, incident reports, any leak repair data, and any failure investigations or abnormal operations records. Providing this information would be critical in ensuring that operators robustly evaluated methods of reducing risk and that the operator did not ignore any material factors in their engineering analysis or an equivalent analysis incorporating operational knowledge.

In a new § 192.1007(c)(3)(iii), PHMSA proposes to require that in evaluating and ranking risks in their DIMP plans, operators of low-pressure gas distribution systems must evaluate the configuration of their primary and any secondary overpressure protection installed at the district regulator stations, the availability of gas pressure monitoring at or near overpressure protection equipment, and the likelihood of any single event that immediately or over time could result in an overpressurization of the low-pressure system (see amended § 192.195(c)). Operators' overpressure protection configurations vary—some include a combination of relief valves, monitoring regulators, or automatic shutoff valves. Other operators have real-time monitoring devices located at the district regulator station, while yet others rely on telemetering devices. Some operators, as demonstrated by the events of September 13, 2018, may have an overpressure protection configuration that can be defeated by a single event, such as excavation damage, natural forces, an equipment failure, or incorrect operations. This amendment would ensure that operators are evaluating their existing overpressure protection system for inadequacies or additional risks that could result in an overpressurization of the system.

6. DIMP—Identify and Implement Measures To Address Risks (Section 192.1007(d))

a. Current Requirements—DIMP—Identify and Implement Measures To Address Risks

Section 192.1007(d) requires operators to determine and implement measures designed to reduce the risks from failure of their gas distribution pipeline systems following the identification of threats (in accordance with § 192.1007(b)) and the evaluation and ranking of risks (in accordance with § 192.1007(c)). Section 192.1007(d) also requires that these risk mitigation measures include an effective leak management program (unless all leaks are repaired when found). Although the specific process is not defined in § 192.1007(d), PHMSA has issued guidance material to support the implementation of these requirements.

In the guidance material, PHMSA states that operators should have a documented list of measures to reduce risks identified on their pipeline system.[87] The process for identifying risk mitigation measures must be based on identified threats to each pipeline segment and the risk analysis. Operators should rank pipeline segments and group segments that represent the highest risk as the most important candidates for which measures are taken to reduce risk. The operator should ensure that the highest priority measures for reducing risk are for the highest-ranked segments as indicated by the risk analysis. Because the design and operation of gas distribution systems are so diverse, no single risk control method is appropriate in all cases. Therefore, the objective of § 192.1007(d) is to ensure that each operator has documented and described existing and proposed measures to address the unique risks to its system and that the operator has evaluated and prioritized actions to reduce risks to pipeline integrity.

b. Need for Change—DIMP—Identify and Implement Measures To Address Risks

Proper implementation of a DIMP plan should result in aggressive oversight and replacement of higher-risk infrastructure. For example, there are many benefits to replacing old, cast-iron, low-pressure distribution pipes with newer materials, such as modern plastic pipe. Replacement projects, however, entail their own risks to public safety and the environment that need to be balanced against the risks associated with leaving a pipeline segment undisturbed. Poorly managed construction projects can result in property damage and personal injury, and replacement activity can include blowdowns to the atmosphere of methane gas that contribute to climate change. Work on existing pipeline facilities can also cause a catastrophic overpressurization, as was the case in CMA's 2018 incident. Operators must manage those risks while still implementing preventive and mitigative measures that would reduce the risk of identified threats.

In 2020, PHMSA issued an advisory bulletin to remind operators of the possibility of failure due to an overpressurization on low-pressure distribution systems.[88] In that advisory bulletin, PHMSA reminded operators of the existing DIMP regulations and recommended that per § 192.1007(d), operators take additional actions to reduce risks if they found their current overpressure protection design to be insufficient. PHMSA also identified for operators that ''[t]here are several ways that operators can protect low-pressure distribution systems from overpressure events,'' such as:

1. Installing a full-capacity relief valve downstream of the low-pressure regulator station, including in applications where there is only worker-monitor pressure control;
2. Installing a ''slam shut'' device;
3. Using telemetered pressure recordings at district regulator stations to signal failures immediately to operators at control centers; and
4. Completely and accurately documenting the location for all control (*i.e.,* sensing) lines on the system.

As discussed earlier, subsequent to the 2018 Merrimack Valley incident, PHMSA was required by statute to ensure that operators of low-pressure gas distribution systems evaluate the risk of overpressurization in their DIMP plans. (49 U.S.C. 60109(e)(7)(A)(ii)). For existing low-pressure systems, operators already have a mechanism in place—their DIMP—to evaluate their systems to ensure they can identify and implement measures to minimize the risk imposed by any inadequate overpressure protection.

c. PHMSA's Proposal To Amend § 192.1007(d)—DIMP—Identify and Implement Measures To Address Risks

PHMSA proposes to amend § 192.1007(d) to establish additional criteria for operators to evaluate when identifying and implementing measures to address risks identified in DIMP plans. PHMSA's proposal would require operators—when identifying and implementing measures—to specifically account for risks associated with the age of the pipe, the age of the system, the presence of pipes with known issues, and overpressurization of low-pressure distribution systems. PHMSA is adding these specific risks to § 192.1007(d) because they were the subject of recent incidents, as discussed earlier. This amendment would ensure that operators are not only identifying these specific threats (in § 192.1007(b)), but also implementing measures to address those risks. In a new § 192.1007(d)(2), PHMSA is proposing to explicitly require operators of existing low-pressure systems to take certain actions to prevent and mitigate the risk of an overpressurization that could be the result of any single event or failure. These actions include identifying, maintaining, and (if necessary) obtaining traceable, verifiable, and complete records that document the characteristics of the pipeline that are critical to ensuring proper pressure controls for the system. PHMSA discusses the criteria for these pressure control records in section IV.F of this NPRM.

In addition to this recordkeeping requirement, in a new § 192.1007(d)(2), PHMSA proposes that operators must confirm and document that each district regulator station meets the design standards in § 192.195(c)(1)–(3) or take the following actions: (1) identify preventative and mitigative measures based on the unique characteristics of their system to minimize the risk of overpressurization on low-pressure systems, or (2) upgrade their systems to meet design standards in § 192.195(c)(1)–(3). PHMSA discusses the criteria for this proposed upgrade in section IV.H of this NPRM. Should an operator choose to identify preventative and mitigative measures based on the unique characteristics of their system to minimize the risk of overpressurization, PHMSA proposes that the operator notify PHMSA and State or local pipeline authorities no later than 90 days in advance of implementing any alternative measures. PHMSA proposes that an operator must make this notification in accordance with § 192.18, which would include a description of the operator's proposed alternative measures, identification, and location of facilities to which the measures would be applied, and a description of how the measures would

[87] DIMP Guidance at 28.

[88] *See* ''Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems,'' ADB–2020–02, 85 FR 61097 (Sept. 29, 2020).

ensure the safety of the public, affected facilities, and environment. This notification would ensure that operators are keeping PHMSA and State authorities informed of alternative measures to address risk. This amendment would apply to existing low-pressure systems that have evaluated and identified inadequate overpressure protections in accordance with § 192.1007(c).

PHMSA has also proposed to amend § 192.18 to reflect this proposed change by including a reference to § 192.1007. Should an operator choose to implement an alternative method of minimizing overpressurization, PHMSA proposes that the operator notify PHMSA and State or local pipeline authorities no later than 90 days in advance of implementing any alternative measures. PHMSA proposes that operators must make this notification in accordance with § 192.18, which would include a description of the operators' proposed alternative measures, identification, and location of facilities to which the measures would be applied, and a description of how the measures would ensure the safety of the public, affected facilities, and environment. This notification would ensure that operators are keeping PHMSA and State authorities informed of alternative measures to address risk.

PHMSA proposes these amendments pursuant to 49 U.S.C. 60102(t) and 60109(e)(7). The proposed amendments would reinforce the recommended actions from PHMSA's 2020 advisory bulletin in which PHMSA identified for operators of low-pressure distribution systems the risks inherent to those systems and the preventative or mitigative measures they should implement to address the risk of overpressurization. PHMSA expects that operators may already be complying with many of these practices subsequent to issuance of the advisory bulletin, which set forth PHMSA's existing policy and interpretation of the current DIMP requirements. In this NPRM, PHMSA proposes to codify this existing policy and interpretation in its regulations.

This amendment is also aligned with the NTSB's clarification to recommendation P–19–14 that PHMSA would not have to require that existing low-pressure gas distribution systems be completely redesigned; rather, PHMSA may satisfy the recommendation by requiring operators to add additional protections, such as slam-shut or relief valves, to existing district regulator stations or other appropriate locations in the system.[89]

7. DIMP—Small LPG Operators (Section 192.1015)

a. Current Requirements—DIMP and Annual Reporting for Small LPG Operators

A ''small LPG operator'' is currently defined at § 192.1001 as an operator of a liquefied petroleum gas (LPG) distribution pipeline system that serves fewer than 100 customers from a single source. Small LPG operators are treated differently in the DIMP regulations than larger operators and they follow their own set of DIMP requirements in § 192.1015 that reflect the relative simplicity of these pipeline systems. The current DIMP requirements for small LPG operators in § 192.1015 are less extensive than for other gas distribution systems, but still provide operator personnel direction for implementing their DIMP plans. Currently, under § 191.11, operators of small LPG systems are not required to submit an annual report to PHMSA.

b. Need for Change—DIMP—Applicability for Small LPG Operators

In the 2009 DIMP Final Rule, PHMSA imposed requirements for small LPG operators similar to those for other operators but with more limited requirements for documentation, consistent with how these operators are treated throughout the pipeline safety regulations. PHMSA did not require operators to report performance measures as they do not file annual reports. Although the DIMP requirements for small LPG operators are similar to those applicable to other operators, PHMSA codified them separately under § 192.1015, emphasizing that DIMPs for small LPG operators should reflect the relative simplicity of their pipeline systems.

On January 11, 2021, PHMSA issued a final rule titled ''Pipeline Safety: Gas Pipeline Regulatory Reform,'' [90] which among other things, excepted master meters from the DIMP requirements. During the development of that rule, PHMSA received several comments in support of extending that exception to small LPG operators. For example, the National Association of Pipeline Safety Representatives (NAPSR) suggested that small gas distribution utilities with 100 or fewer customers—including small LPG operators—should be excepted from the DIMP requirements, stating that many master meter systems, small distribution systems, and small LPG systems typically have no threats beyond the minimum threats listed in § 192.1015(b)(2). Various other commenters, including the National Propane Gas Association (NPGA), AmeriGas, and Superior Plus Propane, voiced support for excepting small LPG operators from the DIMP requirements. The Pipeline Safety Trust did not oppose an exception from DIMP requirements for master meter systems in that rulemaking, only urging PHMSA and its State partners to ensure that master meter operators are managing the integrity risks to their systems outside the context of a DIMP plan. In response, PHMSA in the Gas Regulatory Reform Final Rule stated, ''that the decision about whether to extend the DIMP exception to [other] facilities or to all distribution systems with fewer than 100 customers would benefit from additional safety analysis and notice and comment procedures prior to further consideration.'' PHMSA went on to say that it would ''continue to evaluate the issue of DIMP requirements for small LPG systems and, if appropriate, propose changes in a future rulemaking[.]'' [91]

On December 17, 2021, the NPGA filed a petition for rulemaking in accordance with 49 CFR 190.331.[92] NPGA petitioned PHMSA to amend 49 CFR part 192, subpart P to create an exception for small LPG systems in the DIMP requirements. In support of their petition, they cited that NPGA, PHMSA, and the National Academies of Sciences (NAS) have considered the operation and safety of small LPG systems for more than 10 years.[93] As an alternative, NPGA proposed that PHMSA could enable a special permit (through § 190.341) for small LPG systems, for which NPGA would assist small LPG system operators in providing necessary information to PHMSA in the special permit process.

[89] NTSB clarified this in an official correspondence to PHMSA on July 31, 2020. NTSB, ''Safety Recommendation P–19–014'' (July 31, 2020), *https://data.ntsb.gov/carol-main-public/sr-details/P-19-014*.

[90] 86 FR 2210 (Jan. 11, 2021) (''Gas Regulatory Reform Final Rule''). The comments submitted by stakeholders in this rulemaking may be found in Doc. No. PHMSA–2018–0046.

[91] 86 FR at 2216.

[92] NPGA, Petition for Rulemaking: Small Liquefied Petroleum Distribution Systems, Doc. No. PHMSA–2022–0102–001 (Dec. 17, 2021) (''NPGA Petition'').

[93] NPGA referenced the examples of: (1) PHMSA Gas Regulatory Reform Final Rule, 86 FR 2210; (2) Nat'l Academies of Sciences, Eng'g, and Med., ''Safety Regulation for Small LPG Distribution Systems'' (2018), *https://nap.edu/25245* (''NAS Study''); and (3) NPGA, Comment Re: Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines, Doc. No. PHMSA–RSPA–2004–19854–0197 (Oct. 23, 2008).

The basis of NPGA's petition is that small LPG system operators are comparable to master meter systems, a set of operators that PHMSA recently removed from the DIMP requirements through the 2021 Gas Regulatory Reform Final Rule. As NPGA explained, master meter systems tend to be operated by small entities with simple systems compared to natural gas distribution operators. Master meters also often include only one type of pipe, and the systems operate at a single operating pressure. Similarly, as NPGA stated, the vast majority of small LPG pipeline systems are single property systems that occupy a small, overall footprint in size and generally operate at a single operating pressure. Although such systems may be metered or non-metered, the nature of their simplicity in size and application make them comparable to master meter systems such that, owing to their ''nearly identical'' function and structure, ''the two systems should be categorized together for the same treatment under the regulations'' exempting them from DIMP requirements.[94]

NPGA reiterated that PHMSA further noted in the 2021 Gas Regulatory Reform Final Rule that the agency's experience indicated the analysis and documentation requirements of DIMP had little safety benefit for this type of operator and that focusing on more fundamental risk mitigation activities has more safety benefits than implementing a DIMP for this class of operators. NPGA went on to reiterate PHMSA's position in the Gas Regulatory Reform Final Rule (as discussed above), where PHMSA indicated that exempting master meter operators from subpart P would result in cost savings for master meter operators without negatively impacting safety. NPGA stated that PHMSA had previously expressed its intention to address small LPG systems in a future rulemaking and added that this change would not conflict with the Administration's aims of reducing methane emissions.[95]

PHMSA has reviewed and considered NPGA's petition and agrees with its assertion that small LPG systems do not present the same complexity or incur the same risks as large networks of pipeline systems crossing hundreds of miles. Therefore, PHMSA addresses NPGA's petition through this proposed rule and continued oversight through partnership with State agencies.

PHMSA has concluded that its existing approach requiring small LPG operators to comply with limited DIMP requirements offers little public safety benefit. Small LPG operators by definition have limited systems serving a small number of customers; in fact, NAPSR data suggests that there are only between 3,800 and 5,800 multi-user systems nationwide, with most serving fewer than 50 customers (often well below 50 customers).[96] Small LPG systems are also more simple systems—less piping and fewer components that could fail—that are inherently less susceptible to loss of pipeline integrity than large gas distribution systems. Further, PHMSA incident data indicate that small LPG systems entail relatively low public safety risks. PHMSA's incident data suggest small LPG systems average less than one incident involving a fatality or serious injury per year. Incidents reported by operators to PHMSA from 2010 through 2017 include 10 incidents, seven injuries, and approximately $2 million in property damage.[97] No fatalities have been reported since 2006. Incorporating fire events from the National Fire Incident Reporting System with the PHMSA incident data suggests that the number of incidents involving LPG distribution systems averages in the single digits per year. And, because releases of LPG are not themselves generally considered GHG emissions, continued regulation of small LPG systems pursuant to PHMSA's DIMP requirements provides little benefit for mitigating climate change.

PHMSA understands that even limited DIMP requirements can place a significant compliance burden on small LPG operators and administrative burdens on PHMSA and State regulatory authorities—which in turn can detract from other safety efforts. A 2018 study issued by the NAS found that there is significant regulatory uncertainty among small LPG operators regarding whether PHMSA's DIMP regulations apply at all—resulting in many such operators neither understanding they are obliged to comply with PHMSA regulations nor being regularly inspected by State regulatory authorities.[98]

Given their small size and the relative simplicity of their systems, as discussed in the preceding paragraphs, and the significant compliance burden that DIMP requirements impose on such entities with limited safety benefit, PHMSA has determined that it is more appropriate to exempt small LPG operators from DIMP requirements but impose an annual reporting requirement on these operators.

c. PHMSA's Proposal To Exempt Small LPG Operators From DIMP Requirements and Extend Annual Reporting Requirements to Small LPG Systems

PHMSA proposes to add a new § 192.1003(b)(4) and delete existing § 192.1015 to remove small LPG operators from DIMP requirements but extend annual reporting requirements to these operators. With small LPG operators removed from DIMP requirements at § 192.1015, the definition of small LPG operators in § 192.1001 becomes redundant and therefore PHMSA would also remove it from DIMP. In developing this proposal, PHMSA considered the comments made in the Gas Regulatory Reform Final Rule on the topic of the application of DIMP requirements to small LPG operators, the NPGA's petition for rulemaking, the NAS study, and PHMSA's incident data. PHMSA has preliminarily determined that continuing to impose DIMP requirements (even in the abbreviated form pursuant to existing § 192.1015) on small LPG systems that have been proven by PHMSA incident data to entail inherently limited public safety risks imposes outsized compliance burdens on operators and administrative burdens on PHMSA and State regulatory authorities.[99] At the same time, extending the annual reporting requirement to these operators is intended to ensure that PHMSA will maintain the ability to identify and respond to systemic or emerging issues on those systems.

PHMSA does not expect that this proposed exception from DIMP requirements would adversely impact public safety. As discussed above, PHMSA understands the public safety benefits attributable to existing, limited DIMP requirements for small LPG operators are limited. PHMSA will be able to retain regulatory oversight of small LPG operator systems through

[94] NPGA Petition at 3.

[95] NPGA Petition at 3–5. PHMSA notes that LPG releases are not themselves generally considered to be releases of GHGs.

[96] NAS Study at 83.

[97] NAS Study at 41, Table 3–4.

[98] The NAS Study identified as a source of much of that regulatory uncertainty the varied interpretations of ''public place'' used at § 192.1(b)(5) to determine if certain petroleum gas systems are subject to PHMSA's 49 CFR part 192 regulations. NAS Study at 87–88.

[99] Nor does PHMSA expect that small LPG operators would experience improvements in pipeline safety from the regulatory amendments that PHMSA is proposing in this NPRM for other (larger) gas distribution operators. For example, PHMSA's incident data from 2010 through 2021 shows 12 incidents involving propane gas. In reviewing those incidents, PHMSA found that the age, material type, and operations of low-pressure distribution systems were not relevant to small LPG operators serving fewer than 100 customers; nor did those incidents involved an exceedance of MAOP.

other requirements within 49 CFR part 192, including the proposed annual reporting requirement and the incident reporting requirements at 49 CFR part 191.

To improve the information available to PHMSA and State regulatory authorities for identifying and addressing systemic public safety issues from small LPG systems, PHMSA is proposing to revise § 191.11 to require operators of small LPG systems to submit annual reports using newly designated form PHMSA F 7100.1–2. These annual reports would require operators of small LPG systems to report the location and number of customers served by their distribution pipeline systems, as well as the disposition of any discovered leaks. PHMSA expects that through an annual reporting requirement, PHMSA would also be able to provide better data to the public on small LPG systems, which the agency could assess and may ultimately inform a future rulemaking. PHMSA also expects that its proposal to require annual reporting for small LPG operators may help alleviate the confusion noted by the NAS Study regarding whether those operators are subject to PHMSA regulations at 49 CFR part 192.

PHMSA expects the extension of its part 191 annual reporting requirements to small LPG systems would be reasonable, technically feasible, cost-effective, and practicable. The information PHMSA collects on its current annual report form for gas distribution operators (Form F7100.1–1) does not require significant technical expertise or particularly expensive equipment to populate; small LPG operators may also reduce their burdens further by contracting with vendors to operate and perform maintenance on their systems and complete annual report forms. PHMSA also expects that the forthcoming annual report form (PHMSA F 7100.1–2) specific to small LPG operators will be a further simplified version of the current annual report form. Additionally, PHMSA notes that the information it expects will be collected within that simplified annual report form—operator corporate information, length and composition of the system, leaks on that system, etc.—is minimal information that a reasonably prudent small LPG operator would maintain in ordinary course given that their systems transport pressurized (natural, flammable, toxic, or corrosive) gasses. Viewed against those considerations and the compliance costs estimated in section V.D herein and the PRIA, PHMSA expects the new annual reporting requirement for these operators will be a cost-effective approach to ensuring PHMSA has adequate information to monitor the public safety and environmental risks associated with small LPG systems that would no longer be subject to DIMP requirements. Lastly, PHMSA expects that the compliance timeline proposed for this new reporting requirement—which would begin with the first annual reporting cycle after the effective date of any final rule issued in this proceeding (which would necessarily be in addition to the time since publication of this NPRM)—would provide affected operators ample time to compile requisite information and familiarize themselves with the new annual report form (and manage any related compliance costs).

B. State Pipeline Safety Programs (Sections 198.3 and 198.13)

1. Current Requirements—State Programs and Use of SICT

PHMSA relies heavily on its State partners for inspecting and enforcing the pipeline safety regulations. The pipeline safety regulations provide that States may assume safety authority over intrastate pipeline facilities, including gas pipeline, hazardous liquid pipeline, and underground natural gas storage facilities through certifications and agreements with PHMSA under 49 U.S.C. 60105 and 60106. States may also act as an interstate agent on behalf of DOT to inspect interstate pipeline facilities for compliance with the pipeline safety regulations pursuant to agreement with PHMSA.

To support states' pipeline safety programs, PHMSA provides grants to reimburse up to 80 percent of the total cost of the personnel, equipment, and activities reasonably required by the State agency to conduct its safety programs during a given calendar year. 49 CFR part 198 contains regulations governing grants to aid State pipeline safety programs. PHMSA also maintains ''Guidelines for States Participating in the Pipeline Safety Program'' (''Guidelines''), which contains guidance for how State pipeline safety programs should conduct and execute their delegated responsibilities.[100] The Guidelines promote consistency among the many State agencies that participate under certifications and agreements and are updated on an annual basis.

In 2017, PHMSA adopted within its Guidelines the State Inspection Calculation Tool (SICT), a tool that helps states conduct an inspection activity needs analysis for regulatory oversight of every operator subject to its jurisdiction, for the purpose of establishing a base level of inspection person-days[101] needed to maintain an adequate pipeline safety program.[102] In the SICT, each State agency considers the type of inspection it needs to conduct (*e.g.,* standard, comprehensive, integrity management, operator qualification, damage prevent activities, drug and alcohol); analyzes each operator's system for several risk factors (*e.g.,* cast iron pipe, replacement construction activity, compliance issues); assigns each operator a risk ranking based on the risk factors (*e.g.,* leak prone pipe would have a higher score than modern, coated, and cathodically protected pipe); and lists other unique concerns and considerations (*e.g.,* travel distance to conduct the inspection) applicable to each operator.[103] Each State agency proposes an inspection activity level for each operator, which is subsequently peer-reviewed before being finalized by PHMSA. PHMSA expects that each State agency will dedicate a minimum of 85 inspection person-days for each of its full-time pipeline safety inspectors for pipeline safety compliance activities each calendar year.[104] PHMSA considers a State agency's inspection activity level, among several other factors, when awarding grants to State pipeline safety programs.

2. Need for Change—State Programs and Use of the SICT

A State is authorized to enforce safety standards for intrastate pipeline facility or intrastate pipeline transportation if the State submits annually to PHMSA a certification that complies with 49 U.S.C. 60105(b) and (c). As amended in 2020, the certification includes a requirement that each State agency have the capability to sufficiently review and evaluate the adequacy of each distribution system operator's DIMP plan, emergency response plan, and operations, maintenance, and emergency procedures, as well as ''a

[100] PHMSA, ''Guidelines for States Participating in the Pipeline Safety Program'' (Jan. 2022), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2020-07/2020-State-Guidelines-Revision-with-Appendices-2020-5-27.pdf.*

[101] PHMSA proposes below that an inspection person-day means ''all or part of a day, including travel, spent by State agency personnel in on-site or virtual evaluation of a pipeline system to determine compliance with Federal or State Pipeline Safety Regulations.''

[102] The SICT is located on PHMSA's access restricted database portal.

[103] Instructions for how to use the SICT and inspection activity needs analysis examples are in the Guidelines.

[104] This 85-day requirement is not tied to each individual inspector. It is an 85-day average over all inspectors.

sufficient number of employees'' to help ensure the safe operations of pipeline facilities, as determined by the SICT. (49 U.S.C. 60105(b)). PHMSA updates Guidelines and its evaluation process annually to ensure that State agencies are meeting the certification requirements.[105]

In certifying that the State has a ''sufficient number of employees'', the State must use the SICT to account for:

1. The number of miles of gas and hazardous liquid pipelines in the State, including the number of miles of cast iron and bare steel pipelines;
2. The number of services in the State;
3. The age of the gas distribution systems in the State; and
4. Environmental factors that could impact the integrity of the pipeline, including relevant geological issues.

Currently, the SICT accounts for the size (*e.g.,* mileage, service line count, etc.) of each operator's system; type of operator and product being transported; risk factors of material composition, including but not limited to, the presence of cast iron and bare steel; and environmental factors that could impact the integrity of a pipeline, including geological issues. Total miles of gas and hazardous liquid pipelines in a State and the age of gas distribution systems are, however, only implicitly considered. To comply with the mandate, PHMSA proposes to codify within its regulations the use of the SICT for establishing inspection person-days and update the SICT to explicitly include the total gas or hazardous liquid pipeline mileage in the State and the age of a gas distribution system as a factor for consideration.

3. PHMSA's Proposal To Codify the Use of the SICT in Pipeline Safety Regulations

This NPRM proposes amendments to the pipeline safety regulations at 49 CFR part 198 to codify use of the SICT by all PHMSA's State partners holding certifications or agreements per 49 U.S.C. 60105 or 60106. Specifically, PHMSA proposes to revise § 198.3 to add definitions for ''inspection person-day'' and ''State Inspection Calculation Tool'' and by revising § 198.13 to include the use of the SICT for determining inspection person-days. PHMSA proposes to define ''inspection person-day'' to mean ''all or part of a day, including travel, spent by State agency personnel in on-site or virtual evaluation of a pipeline system to determine compliance with Federal or State Pipeline Safety Regulations.'' PHMSA will continue to permit travel to be included for inspection person-days even if travel requires a full day before or after the inspection because some states cover a large geographical area that requires substantial travel time and a State agency's staffing requirement could be impacted if travel is not considered. PHMSA will also continue to allow inspection person-days to be counted for those individuals who have not completed training requirements but who assist in inspections if they are supervised by a qualified inspector. PHMSA proposes to define the term ''State Inspection Calculation Tool (SICT)'' to mean ''a tool used to determine the required minimum number of annual inspection person-days for a State agency.'' These proposed definitions are consistent with those in the Guidelines.

PHMSA is required to promulgate regulations to require that a State authority with a certification under 49 U.S.C. 60105 has a sufficient number of qualified inspectors to ensure safe operations, as determined by the SICT and other factors determined appropriate by the Secretary. (49 U.S.C. 60105 note). Pursuant to this legal requirement, PHMSA proposes revising § 198.13(c)(6) to state that when allocating funding and considering various performance factors, PHMSA considers the number of State inspection person-days, ''as determined by the SICT and other factors.'' These amendments would codify PHMSA's current practice of using the SICT in the determination of the minimum number of inspection person-days each State must dedicate to inspections in a given calendar year.

C. Emergency Response Plans (Section 192.615)

The pipeline safety regulations require operators to have written procedures for responding to emergencies involving their pipeline systems to ensure a coordinated response to a pipeline emergency. This response includes communicating with fire, police, and other public officials promptly. Through a final rule issued on April 8, 2022, titled ''Requirement of Valve Installation and Minimum Rupture Detection Standards'', PHMSA extended that emergency communication for all gas pipeline operators to include a public safety answering point (PSAP; *i.e.,* 9–1–1 emergency call center).[106] Among other changes, the Valve Rule amended § 192.615(a) to ensure proper communication with PSAPs, requiring operators to immediately and directly notify PSAPs upon notification of a potential rupture. However, the Valve Rule requirements were not in effect at the time of the Merrimack Valley incident.

Subsequent to the 2018 Merrimack Valley incident, 49 U.S.C. 60102 was amended to improve the emergency response and communications of gas distribution operators during gas pipeline emergencies in several ways. Specifically, 49 U.S.C. 60102(r) was added, which requires PHMSA to promulgate regulations ensuring that gas distribution operators develop written emergency response procedures for notifying and communicating with emergency response officials as soon as practicable from the time of confirmed discovery of certain gas pipeline emergencies; communicate with the public during and after such a gas pipeline emergency; and establish an opt-in system for operators to rapidly communicate with customers. Gas distribution operators must make their updated emergency response plans available to PHMSA or the relevant State regulatory agency within 2 years after the final rule is issued, and every 5 years thereafter (49 U.S.C. 60108(a)(3)).

PHMSA, in this NPRM, proposes building on the Valve Rule's changes to emergency response plan requirements through additional changes to ensure prompt and effective emergency response coordination. For all gas pipeline operators subject to § 192.615,[107] PHMSA proposes to expand the requirements to have procedures for a prompt and effective response to include emergencies involving notification of potential ruptures, a release of gas that results in a fatality, and any other emergencies deemed significant by the operator, with similar requirements to notify PSAPs in those instances. PHMSA understands these proposed amendments of existing emergency response plan requirements as applicable to all part 192-regulated pipelines would be reasonable, technically feasible, cost-effective, and practicable. The proposed changes are common-sense, incremental supplementation of current requirements regarding the content and execution of emergency response plans for gas pipeline operators.

[105] PHMSA anticipates issuing updated Guidance to reflect the changes to the Pipeline Safety Grant Program.

[106] 87 FR at 20940, 20973.

[107] PHMSA notes that § 192.9(d) does not currently require compliance with § 192.615 for Type B gathering lines, however PHMSA has proposed, in another rulemaking, to amend § 192.9(d) to require Type B gas gathering operators to comply with § 192.615. *See* 88 FR at 31952–53, 31955–56.

Implementation of the proposed requirements should not require special expertise or investment in expensive new equipment; PHMSA expects that some operators may already comply with these proposed requirements either voluntarily or due to similar requirements imposed by State pipeline safety regulators. And insofar as these incremental proposed additions to emergency planning requirements are consistent with historical PHMSA guidance, industry operational experience, and the lessons learned from incidents such as the Merrimack Valley incident, they are precisely the sort of actions a reasonably prudent operator of any gas pipeline facility would maintain in ordinary course given that their systems transport commercially valuable, pressurized (natural flammable, toxic, or corrosive) gasses. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments are a cost-effective approach to achieving the commercial, public safety, and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—one year after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their procedures (and manage any related compliance costs).

PHMSA proposes additional requirements for gas distribution operators. First, those operators would be subject to an expanded list of emergencies that includes unintentional releases of gas with significant associated shutdown of customer services. Second, gas distribution operators must establish written procedures for communications with the general public during an emergency, and continue communications through service restoration and recovery efforts, to inform the public of the emergency and service restoration and recovery efforts. Third, gas distribution operators would be required to develop and implement for their customers an opt-in or opt-out notification system to provide them with direct communications during a gas pipeline emergency. PHMSA understands its proposed amendments enhancing existing emergency response plan requirements would be reasonable, technically feasible, cost-effective, and practicable for affected gas distribution operators. PHMSA expects that some gas distribution operators may already comply with these requirements either voluntarily or due to similar requirements imposed by State pipeline safety regulators. PHMSA also expects that operators will already have (due to the need to bill their customers) the requisite contact information needed to implement voluntary opt-in or opt-out notification systems; as explained below, some operators may also be able to leverage existing emergency notification systems maintained by local and State government officials in satisfying this proposed requirement. PHMSA further notes that its proposed enhancements for emergency communications are precisely the sort of minimal actions a reasonably prudent operator of gas distribution pipeline facility would undertake in ordinary course to protect each of (1) the public safety, given that their systems transport pressurized (natural, flammable, toxic, or corrosive) gasses; and (2) their customers, given the economic cost to those customers from interruption of supply. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects its proposed amendments will be a cost-effective approach to achieving the public safety and environmental benefits discussed in this NPRM and its supporting documents. Lastly, PHMSA understands that its proposed compliance timeline—between 12 to 18 months after publication of a final rule (which would necessarily be in addition to the time since publication of this NPRM)—would provide operators ample time to implement requisite changes to their procedures and procure necessary personnel and vendor services (and manage any related compliance costs).

Finally, PHMSA is requesting comments on whether it should require gas distribution operators to follow incident command systems (ICS) during an emergency response. PHMSA may consider whether to include this requirement in any final rule in this proceeding. The sections below discuss each of these proposals in more detail.

1. Emergency Response Plans—First Responders

a. Current Requirements—Emergency Response Plans—Notifying PSAPs, First Responders, and Public Officials

Section 192.615(a) requires that each gas pipeline operator have written procedures for responding to gas pipeline emergencies, including for how operators are expected to communicate with fire, police, and other appropriate public officials before and during an emergency. The Valve Rule revised § 192.615(a)(2) to add direct communication with PSAPs in response to gas pipeline emergencies and required operators to establish and maintain an adequate means of communication with PSAPs.[108] Further, the Valve Rule revised § 192.615(a)(8) to require operators to notify these entities and coordinate with them during an emergency. This communication to the appropriate PSAPs must occur immediately and directly upon receiving a notification of potential rupture to coordinate and share information to determine the location of any release.[109] The Valve Rule also revised § 192.615(c) to require each operator establish and maintain liaison with the appropriate PSAPs ''where direct access to a 9–1–1 emergency call center is available from the location of the pipeline, as well as fire, police, and other public officials'' to coordinate responses and preparedness planning.

Further, PHMSA issued an advisory bulletin in 2012 (ADB–2012–09) regarding communications between pipeline operators and PSAPs.[110] In the advisory bulletin, PHMSA reminded operators that they should notify PSAPs of indications of a pipeline facility emergency, including an unexpected drop in pressure, an unanticipated loss of SCADA communications, or reports from field personnel. In the advisory bulletin, PHMSA recommended that pipeline operators immediately contact the PSAPs of the communities in which such indications occur. Furthermore, the advisory bulletin noted that operators should have the ability to immediately contact PSAPs along their pipeline routes if there is an indication of a pipeline emergency to determine if the PSAP has information that may help the operator confirm whether a pipeline emergency is occurring or to provide assistance and information to public safety personnel who may be responding to the event. The revisions to § 192.615 in the Valve Rule essentially codified this advisory.

[108] PHMSA expects that ''maintaining adequate means of communication'' should include, but not be limited to, considering the frequency of communication, changes to the nature of the emergency, changes to previously liaised information, and updates to other emergency response information, as determined by the operator.

[109] 87 FR at 20983.

[110] ''Pipeline Safety: Communication During Emergency Situations,'' ADB–2012–09, 77 FR 61826 (Oct. 11, 2012). PHMSA also issued draft FAQs on 9–1–1 notification on July 8, 2021. ''Frequently Asked Questions on 911 Notifications Following Possible Pipeline Ruptures,'' 86 FR 36179 (July 8, 2021). If PHMSA were to finalize the proposed revisions for these emergency plan provisions in a subsequent final rule, PHMSA would withdraw the draft 9–1–1 notification FAQs as redundant.

PHMSA notes that indications of a gas pipeline emergency, including unexpected pressure drops or reports from field personnel, might be a notification of potential rupture under amended § 192.615, which would require the direct and immediate notification of the appropriate PSAP.

b. Need for Change—Emergency Response Plans—Notifying PSAPs, First Responders, and Public Officials

During the initial response to the 2018 Merrimack Valley incident, the three fire departments in the affected municipalities were inundated with emergency calls from residents and businesses reporting fires and explosions and requesting assistance shortly after 4 p.m. on September 13, 2018. Around that same time, the CMA technician reported smoke and explosions. However, it was not until nearly 4 hours later at 7:43 p.m. that the president of CMA declared a ''Level 1'' emergency under CMA's emergency response plan. Lawrence's deputy fire chief told NTSB investigators that, during the incident response, he attempted to contact CMA through the station dispatch to get a status update to see if CMA had the gas incident under control but did not receive updates from the company until hours later. About 2 hours after the initial fires, Lawrence's deputy fire chief assumed the gas company had resolved the incident.[111] The Andover fire chief recognized the events occurring were gas-related and contacted CMA through a regular dispatch number to provide status updates so the fire department could relay information to the public. He told NTSB investigators that CMA did call him back more than 4 hours later, while also acknowledging the delay was likely caused by the number of emergency calls CMA received.

The NTSB report noted that CMA had emergency response plans but did not implement their plans in a manner that would allow them to effectively respond to such a large incident, explaining that ambiguities within the operator's emergency response plans could have contributed to the poor emergency response in that incident. Specifically, the NTSB pointed out that the operator's emergency response plans suggested that notification could be discretionary, as those procedures stated that when an overpressurization of the system occurs, there ''may be a need'' to communicate with local government officials and emergency management agencies, as well as with fire and police departments.[112] According to the NTSB report, the NiSource emergency plan also stated that it is ''imperative for all entities involved to remain informed of each other's activities,'' and that CMA's Incident Commander (IC), (in this case, the field operations leader (FOL)) was required to establish appropriate contacts for communication purposes throughout the incident. However, during the initial hours of the event, the IC did not establish these requisite communication contacts because the IC was involved with shutting down the natural gas system. And although CMA representatives went to emergency responder staging areas and emergency operations centers, the NTSB report noted that CMA representatives could not address many of the questions from emergency responders because the representatives were not prepared with thorough and actionable information. As a result of the lack of timely, thorough, and actionable information on the circumstances of the overpressurization event, emergency responders unnecessarily evacuated areas, straining limited emergency response resources, and creating confusion among the public. The NTSB concluded that CMA was not adequately prepared with the resources necessary to assist emergency management services with the emergency response.

Subsequent to the 2018 Merrimack Valley incident, PHMSA was required by law to promulgate regulations to ensure that gas distribution system operators include in their emergency response plans written procedures for notifying ''first responders and other relevant public officials as soon as practicable, beginning from the time of confirmed discovery, as determined by [PHMSA], by the operator of a gas pipeline emergency,'' and including gas distribution-specific indications of what constitutes a gas pipeline emergency. (49 U.S.C. 60102(r)).

c. Proposal To Amend § 192.615—Emergency Response Plans—Notifying PSAPs, First Responders, and Public Officials

As discussed earlier, the Valve Rule revised the existing emergency response regulations to require operators notify PSAPs in the event of gas pipeline emergencies, and immediately and directly notify PSAPs when receiving a notification of potential rupture. In this NPRM, PHMSA proposes to revise the non-exclusive list at § 192.615(a)(3) of gas pipeline emergencies requiring all part 192-regulated gas pipeline operators to undertake prompt, effective response on notification of potential ruptures; a release of gas that results in one or more fatalities; and any other emergency deemed significant by the operator. PHMSA is also proposing that gas distribution pipeline operators would need to undertake prompt, effective response on notification of the unintentional release of gas and shutdown of gas service to either 50 or more customers or, if the operator has fewer than 100 customers, 50 percent of total customers. Additionally, PHMSA proposes to amend existing requirements at § 192.615(a)(8) to apply its requirement for operators of all gas pipelines to establish written procedures for immediately and directly notifying PSAPs, or other coordinating agencies for the communities and jurisdictions in which the pipeline is located, to include after a notification of these gas pipeline emergencies. Gas distribution operators, moreover, would also have to immediately and directly notify PSAPs on notification of an unintentional release and shutdown of gas services where either 50 or more customers lose service, or for operators with fewer than 100 customers, if 50 percent of all the operator's customers lose service.

i. What is a ''Gas Pipeline Emergency?''

PHMSA is revising the list of gas pipeline emergencies in § 192.615(a)(3) to add: (1) for all part 192-regulated gas pipeline operators, events involving 1 or more fatalities or any other emergency deemed significant by the operator; and (2) for gas distribution pipeline operators only, an unintentional release of gas resulting in a shutdown of gas services affecting at least 50 customers, or for operators with fewer than 100 customers, 50 percent of customers.[113]

The statutory language does not elaborate on the meaning of ''significant'' within its usage in the phrase ''the unscheduled release of gas and shutdown of gas service to a significant number of customers.'' Therefore, PHMSA proposes to establish the threshold for a ''significant number of customers'' to be 50 customers or, for operators with fewer than 100 customers, 50 percent of all the operator's customers. In determining this threshold, PHMSA reviewed the

[111] NTSB, PLD18MR003, ''Interview of: Kevin Loughlin, Deputy Chief Lawrence Fire Department,'' (Sept. 15, 2018), *https://data.ntsb.gov/Docket/Document/docBLOB?ID=40476257&FileExtension=.PDF&FileName=Emergency%20Response%20-%20Interview%20of%20Lawrence%20Deputy%20Fire%20Chief-Master.PDF.*

[112] NTSB/PAR–19/02 at 46.

[113] PHMSA also is adding, applicable to all part 192-regulated gas pipeline operators, ''potential rupture'', consistent with the amendment in the Valve Rule to § 192.615(a)(8).

data for all reportable gas distribution incidents from 2010 to 2021 and averaged the number of residential, commercial, and industrial customers affected by those incidents.[114]

PHMSA also proposes to add ''other emergency deemed significant by the operator'' to the list of examples of a gas pipeline emergency to allow operators to use their best professional judgment when coordinating with first responders and other relevant public officials and account for other system-specific circumstances, such as an outage to a single customer that happens to be a hospital or other critical-use facility, when complying with § 192.615. This amendment would specify a non-exclusive list of gas pipeline emergencies.

ii. When must operators communicate with PSAPs, first responders, and other relevant public officials?

PHMSA proposes to adopt the aforementioned more-inclusive list of gas pipeline emergencies into the § 192.615(a)(8) notification requirements established in the Valve Rule that required the immediate and direct notification of PSAPs and other relevant emergency responders and public officials after receiving notice of such an emergency. Pursuant to 49 U.S.C. 60102(r), operator communications with first responders and other relevant public officials must occur ''as soon as practicable, beginning from the time of confirmed discovery, as determined by the Secretary, by the operator of a gas pipeline emergency.'' PHMSA, in §§ 191.5 and 195.52, already uses the term ''confirmed discovery'' [115] to require operators to report certain events to the National Response Center at the earliest practicable moment following ''confirmed discovery;'' however, these notifications may occur up to 1 hour after confirmation. Further, those §§ 191.5 and 195.52 reportable events may not always constitute a gas pipeline emergency as proposed in § 192.615. Because the 49 U.S.C. 60102(r) mandate directs PHMSA to improve and expand emergency response efforts—distinct from operator notification of incidents/accidents for reporting purposes—PHMSA determines that the timing of local emergency communication must come immediately and directly upon indication of such a gas pipeline emergency. PHMSA, therefore, does not propose to interpret ''confirmed discovery'' in 49 U.S.C. 60102(r) to apply in § 192.615(a) in the same manner as the term is used in 49 CFR parts 191 and 195.[116] Instead, PHMSA proposes ''confirmed discovery'' in 49 U.S.C. 60102(r), for purposes of § 192.615, to mean immediately after receiving notice of a gas pipeline emergency.[117] This will bring local emergency services to bear as near as possible to a gas pipeline emergency based on early indications, rather than considering whether the gas pipeline emergency is also a reportable event under § 191.5 before initiating an emergency response.

PHMSA proposes that gas pipeline emergencies be immediately and directly communicated to local emergency responders because any delays in emergency response may make the emergency significantly more difficult to contain. PHMSA expects that in no case should that ''immediate'' communication to PSAPs begin any later than 15 minutes following initial notification to the operator of that emergency. This expectation is consistent with certain criteria for ''notification of a potential rupture'' adopted in the Valve Rule,[118] and would ensure the timely and effective implementation of the pipeline operator's emergency response plan and coordinated response with local public safety officials. PHMSA also expects that if a gas pipeline emergency also meets the criteria of an incident in § 191.3, operators would report the incident to the National Response Center in accordance with § 191.5, as already required.

iii. What information should operators provide to first responders and public officials?

As the emergency response to the Merrimack Valley incident continued, public safety officials asked CMA for detailed information on the locations of the overpressurized gas lines to aid in assessing the scope and scale of the incident. Officials requested maps and lists of impacted customers and impacted streets, but CMA did not provide them in a timely manner. This significantly hampered the response to the event and caused first responders to take unnecessary actions during the immediate response efforts. For example, instead of targeting specific residents based on the location of the affected services, first responders needed to go door to door to evaluate safety impacts and determine where the gas lines were overpressurized. To prevent such delays from occurring in the future, PHMSA recommends operators provide first responders and public officials with pertinent information, as it becomes available, to support emergency communications during a gas pipeline emergency, including: (1) the operator's response efforts; (2) information on the gas service sites impacted by the release; (3) the magnitude of the incident and its expected impact; (4) the location(s) of the emergency and of affected customers; (5) the specific hazard and the potential risks; and (6) the operator point of contact responsible for addressing first responder and public official questions and concerns. Procedures to provide such information must be included in their emergency response plans and should also comport with guidance by the Federal Emergency Management Agency (FEMA) for State and local governments in developing effective hazard mitigation planning and would help ensure that appropriate instructions, directions, and information is provided to the right people at the appropriate time.[119]

2. Emergency Response Plans—General Public

a. Current Requirements—Emergency Response Plans—General Public

Currently, there are no Federal regulations requiring gas distribution operators to establish communications with the general public during or following a gas pipeline emergency. Section 192.615 requires operator

[114] *See* PHMSA, ''Distribution, Transmission & Gathering, LNG, and Liquid Accident and Incident Data'' (Aug. 31, 2022), *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.*

[115] The term ''confirmed discovery,'' defined at §§ 191.3 and 195.3, ''means when it can be reasonably determined, based on information available to the operator at the time a reportable event has occurred, even if only based on a preliminary evaluation.''

[116] Relying on the same operative phrase (''confirmed discovery'') that is already used to notify the National Response Center of reportable incidents risks introducing confusion and uncertainty with respect to what regulations to follow and how to incorporate these regulations into response plans for when operators must contact local emergency responders. In an emergency, clarity is critical and PHMSA believes that utilizing distinct regulatory phrases for these different duties will help distinguish and clarify responsibilities in an emergency response.

[117] PHMSA's proposal anticipates that an operator will alert local emergency response officials upon earliest indications of gas pipeline emergencies.

[118] *See* § 192.635(a)(1) (specifying a 15-minute time interval for evaluating significant pressure losses on gas pipelines as an indicium of a rupture).

[119] FEMA, ''Lesson 3: Communicating in an Emergency'' (Feb. 2014), *https://training.fema.gov/emiweb/is/is242b/instructor%20guide/ig_03.pdf.*