(because of a lack of qualified inspection personnel) on these pipelines would be particularly compelling given their (typical) location near or within population centers. PHMSA believes this proposed amendment addresses concerns raised in APGA's petitions for reconsideration regarding the unintended burdens of the March 2015 rulemaking on small operators.

PHMSA acknowledges that NAPSR, in its 2011 resolution and petition for reconsideration of the March 2015 final rule, called for limiting the prohibition to contractor personnel inspecting the work of their own crew, as NAPSR does not view an ''inherent conflict of interest'' arising from operator-employed personnel doing the same.[175] PHMSA agrees with NAPSR that a lack of independence in inspection activity raises public safety concerns but disagrees that there is a material distinction in risk between those personnel directly employed by the operator and those third-party personnel contracted by the operator. Further, creating such a distinction could diminish the scope of the safety benefit while placing burden on smaller operators who rely on contractors for a large portion of their construction work. Therefore, PHMSA does not see a reasoned basis to discriminate between operator personnel and contracted personnel for the purposes of this inspection.

PHMSA understands this proposed amendment to restore a previously approved (but now suspended) requirement that post-construction inspections be performed by personnel other than those who performed the construction work being inspected would be reasonable, technically feasible, cost-effective, and practicable for all affected operators. That requirement reflects the proposition—reflected in industry best practice—that an independent second set of eyes inspecting a construction project provides more robust assurance of work product quality than allowing construction personnel to inspect their own work. Although PHMSA acknowledges that this proposed requirement could entail additional compliance burdens (in terms of costs and stretching limited personnel resources) for some operators, PHMSA believes those burdens would be manageable because (1) all operators could account for them at the project planning phase in a way that allows them to control costs or secure requisite supplemental personnel (or contractors), and (2) small gas distribution system operators whose limited personnel resources would make them dependent on (potentially expensive) contractors would be excepted from this requirement. 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 procedures and obtain access to inspection personnel for near-term installation projects (as well as manage any resulting compliance costs).

J. Records: Tests (Sections 192.517 and 192.725)

1. Current Requirements—Records: Tests

Section 192.517(b) applies to all gas pipeline operators and states that ''[e]ach operator must maintain a record of each test required by §§ 192.509 [pipelines operating below 100 psig], 192.511 [service lines], and 192.513 [plastic pipelines], respectively, for at least 5 years.'' Section 192.725(a) states that ''each disconnected service line must be tested in the same manner as a new service line, before being reinstated.''[176]

2. Need for Change—Records: Tests

On October 7, 2021, NAPSR submitted a resolution seeking that PHMSA amend § 192.517(b) in several ways. NAPSR recommended PHMSA amend its regulations to require operators to retain test documentation under § 192.517(b) for the life of the corresponding pipeline segment as opposed to the current 5 years.[177] The resolution also requested that PHMSA require operators to retain for the life of the pipeline ''the test pressure documentation created within the five years prior'' to any such amendment. Additionally, NAPSR requested that PHMSA require additional, more detailed, information be documented as part of these test records. PHMSA agrees that the detailed recordkeeping content and retention requirements suggested by NAPSR will improve consistency and promote public safety and protection of the environment.

NAPSR also requested that PHMSA add § 192.725 (''Test requirements for reinstating service lines'') to the list of required test records in § 192.517(b). It reasoned that § 192.603(b), which requires operators to keep records necessary to administer the procedures established under § 192.605, is potentially in conflict with § 192.517. PHMSA clarifies that the requirement in § 192.725 to perform a test ''in the same manner as a new service line'' is meant to direct an operator to conduct a test required for a new service line in accordance with 49 CFR part 192, subpart J. A test performed to meet § 192.725 does not constitute a new type of test for purposes of identifying recordkeeping requirements for such a test. PHMSA expects an operator to select the appropriate test in subpart J to meet the testing requirement of § 192.725, which includes meeting the corresponding recordkeeping requirements of § 192.517. For that reason, PHMSA does not propose to include § 192.725 in the list of tests identified within § 192.517.

3. Proposal To Amend § 192.517—Records: Tests

PHMSA proposes to amend § 192.517 to require that records of tests covered by § 192.517(b) (*i.e.,* tests performed according to § 192.509, 192.511, and 192.513) be retained for the life of the pipeline. This amendment would be applicable to all gas pipeline operators. PHMSA would require operators to retain the records for all tests presently being retained under the existing language of § 192.517(b) from the preceding five years, which under the proposal would then be retained for the life of the pipeline. PHMSA also proposes to require that the records of these tests include, at a minimum, sufficient information to document the test, including information about the

[175] *See* NAPSR, Res. 2015–01, ''A Resolution Seeking Suspension of the Effective Date of a Recently Adopted Federal Final Rule, and Reconsideration of that Rule,'' at 2 (Sept. 3, 2015), *https://www.napsr.org/resolutions.html.*

[176] Paragraph (b) provides an exception to paragraph (a) for any part of the original service line used to maintain continuous service during testing if provisions are made to maintain continuous service.

[177] NAPSR, Res. 2021–02, ''A Resolution Seeking a Modification of 49 CFR 192.517(b) to Require Certain Distribution Pipeline Pressure Test Information Be Documented and to Require the Retention of Test Documentation for Distribution Pipelines for the Lifetime of the Corresponding Pipeline Segment,'' Doc. No. PHMSA–2021–0046–0005 (Oct. 7, 2021). This extended retention period would include records of tests establishing an MAOP, as NAPSR explains in its petition: ''PHMSA has set forth regulations requiring the availability and use of pipeline pressure documentation to establish the maximum allowable operating pressure (MAOP) of pipelines, including short segments of replaced or relocated pipe, prior to placing them in service within Subpart L of 49 CFR 192, specifically 49 CFR 192.619.''

operator, the individual or any company used to perform the test, pipeline segment being tested, test date, medium, pressure, duration, and any leaks or failures noted and their disposition. Retaining tests for the life of the pipeline, instead of the current retention period of 5 years, ensures that records are available whenever repairs are necessary, or should an incident occur, records are available to support an operator's inspection and investigation into the root cause of a failure. Further, PHMSA currently requires (per § 192.603(b) and § 192.605) operators to keep MAOP records for life of facility but MAOP records established by § 192.517(b) tests are just 5 years. PHMSA believes that these changes will improve the quality and availability of test records, including records of leaks occurring during testing activities and MAOP establishment records.

PHMSA understands this proposed amendment of an existing record retention requirement to be reasonable, technically feasible, cost-effective, and practicable. The proposed changes are incremental supplementation of current requirements regarding recording and retaining record of pressure tests operators are already required to conduct. The proposed amendments require operators to document information they may already be obtaining through the required tests under this current requirement, more clearly states that information which operators should record from the tests and extends the retention period; PHMSA expects some operators may already be in their substantial compliance with this proposed requirement. 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 procedures to ensure identification or generation of pertinent records (and manage any related compliance costs).

4. Proposal To Amend § 192.725—Test Requirements for Reinstating Service Lines

PHMSA proposes to revise § 192.725 to clarify that ''tested in the same manner as a new service line'' in the existing regulation means ''tested in accordance with subpart J of this part'', by inserting that clarifying language within a parenthetical. PHMSA understands that this proposed revision merely clarifies an existing requirement and is therefore technically feasible and practicable. PHMSA further notes 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 updates, if any are needed, to their procedures.

K. Miscellaneous Amendments Pertaining to Part 192—Regulated Gas Gathering Pipelines (Sections 192.3 and 192.9)

1. Current Requirements—Gas Gathering

Among the regulatory amendments adopted in the April 2022 Valve Rule were enhanced emergency planning and notification requirements applicable to all part 192-regulated gas pipeline operators subject to § 192.615, to include new references to public safety answering points (such as 9–1–1 call centers) and a requirement for those operators to update their written procedures to provide for timely rupture identification; certain new, implementing definitions at § 192.3 applicable to all part 192-regulated gas pipelines; and within a new § 192.635, a definition of the term ''notification of potential rupture'' applicable to those part 192-regulated pipelines subject to that provision.

The D.C. Circuit, however, vacated those new requirements as to gas gathering pipelines in a decision issued in May 2023.[178] PHMSA subsequently issued a Technical Correction codifying the court's decision by introducing exceptions to the above provisions restricting their application to the part-192 regulated gas gathering pipelines to which they had applied.[179] Specifically, the Technical Correction introduced language in each of the § 192.3 definitions adopted in the Valve Rule (''entirely replaced onshore transmission pipeline segments''; ''notification of potential rupture''; and ''rupture-mitigation valve (RMV)'') excepting all part 192-regulated gas gathering pipelines from those definitions. The Technical Correction also introduced a series of exceptions within the regulatory cross-reference provision at § 192.9 preventing application of the Valve Rule's amendments at §§ 192.615 and 192.635 regarding emergency response and notification and rupture identification procedures to each of offshore gas gathering pipelines (§ 192.9(b)) as well as onshore Types A (§ 192.9(c)) and C (§ 192.9(e)) gas gathering pipelines.

2. Need for Change—Gas Gathering

Written emergency planning and notification procedures are critical tools for the safe operation of any gas pipeline. Offshore, Type A, and Type C gas gathering pipelines had—consistent with the risks to public safety and the environment posed by an emergency involving those high-pressure, gas pipeline facilities[180]—been subject to extensive emergency planning and notification requirements before issuance of the Valve Rule in April 2022. Those long-standing safety standards include requirements for operators to have written emergency procedures for notifying, establishing, and maintaining communications with fire, police, and other public officials (§ 192.615(a)(2) and (8); § 192.615(c)); taking actions necessary to minimize hazards to public safety from the emergency (§ 192.615(a)(6)); and directing operator control room response actions in an emergency (§ 192.615(a)(11)).

The amendments to § 192.615 introduced in the Valve Rule were modest refinements to those long-standing emergencies response planning and notification requirements. The Valve Rule explained its amendments to § 192.615(a)(2), (a)(8), and (c) adding language requiring notification of, and communication with, public safety answering points (PSAPs) or emergency coordination agencies ensure notifications of pipeline emergencies are channeled to resources best positioned to alert first responders and coordinate response efforts across multiple jurisdictions that may be affected by a pipeline emergency.[181] The Valve Rule also made a pair of incremental changes to § 192.615(a)(6)'s requirement that operator procedures provide for taking certain actions—emergency shutdown or pressure reduction—to minimize public safety risks. The first change was to add language (''including, but not limited to . . .'') clarifying that operator procedures could provide for actions

[178] *GPA Midstream Assn.* v. *Dep't of Transp.,* 67 F.4th 1188, 1201 (D.C. Cir. 2023).

[179] 88 FR at 50058, 50060–61 (Aug. 1, 2023).

[180] *See, e.g.,* ''Gas Gathering Line Definition; Alternative Definition for Onshore Lines and New Safety Standards—Final Rule,'' 71 FR 13292, 13296–97 (Mar. 15, 2006) (discussing safety basis for broadly extending part 192 requirements for gas transmission lines to Type A gas gathering pipelines); 86 FR at 63284–85 (discussing safety basis for extending § 192.615 requirements to high-pressure, large-diameter Type C gas gathering pipelines).

[181] 87 FR at 20969–70, 20973.

other than system shutdown or pressure reduction in an emergency, thereby granting operators greater flexibility in designing response actions best capable of minimizing hazards in a pipeline emergency; this includes the additionally enumerated action of valve shut-off. The second change included a reference to environmental hazards. Among those hazards operator procedures must minimize, reflecting the fact that the mechanism for public safety and environmental harms (namely, the release of gas from a pipeline) is identical.

The Valve Rule also made several regulatory amendments to address the time-dependent [182] risks to public safety and the environment posed by ruptures on gas pipelines. First, the Valve Rule added at § 192.3 (which in turn references a new § 192.935) the new term ''notification of potential rupture'' codifying commonly-understood indicia of a rupture.[183] The Valve Rule also added a pair of requirements ensuring timely identification of, and response to, this particular emergency in which every second lost can increase public safety and environmental consequences: a new § 192.615(a)(12) requiring operators develop procedures for confirming actual ruptures following reports of the indicia listed in the new definition of ''notification of potential rupture'', as well as language at § 192.615(a)(8) introducing a new requirement for immediate and direct notification of PSAPs on an operator's notification of a potential rupture.[184] Similarly, PHMSA enhanced a longstanding requirement at § 192.615(a)(11) governing emergency procedures for control room personnel by adding a cross-reference to newly-adopted provisions pertaining to rupture mitigation valves at §§ 192.634 and 192.636.

Lastly, the Valve Rule adopted certain other definitions of terms (''entirely replaced onshore transmission segment''; and ''rupture-mitigation valve'') employed in its regulatory amendments.

3. Proposal To Amend §§ 192.3 and 192.9—Emergency Procedures and Notification; Rupture Identification Procedures

PHMSA proposes several amendments to restore certain emergency planning, notification, and rupture identification procedures vacated by the D.C. Circuit with respect to gas gathering pipelines. First, PHMSA proposes to delete from each of the § 192.3 definitions introduced in the Technical Correction language disclaiming application of those terms to any part 192-regulated gas gathering line.[185] Second, PHMSA proposes to delete from § 192.9 similar language excluding application of the Valve Rule's amendments to § 192.615 discussed in section IV.K.2 above to offshore gas gathering (§ 192.9(b)), Type A (§ 192.9(c)), and Type C (§ 192.9(e)) gas gathering lines. This proposal is focused on application of these emergency response provisions to gathering lines; PHMSA is not, however, proposing in this rulemaking to restore application to part 192-regulated gas gathering lines of other regulatory amendments adopted in the Valve Rule pertaining to rupture mitigation valve installation, operation, and maintenance.

As explained in section IV.K.2 above, the Valve Rule's amendments to § 192.615 are incremental improvements on existing requirements applicable to offshore, Type A, and Type C gas gathering pipelines. Some of those amendments are broad in scope and are applicable to any emergency on those gas gathering pipelines; others are specific to ruptures on those pipelines. And each of those amendments is a common-sense, baseline expectation ensuring operator emergency planning and notification procedures are directed toward timely and effective response and mitigation of risks to public safety and the environment.

PHMSA understands these proposed amendments would be reasonable, technically feasible, cost-effective and practicable for affected gas gathering pipeline operators. The restoration of definitions at § 192.3 are not themselves operative provisions entailing compliance burdens for operators; several of those definitions, moreover, are used in operative provisions inapplicable to gas gathering pipelines. And although the restored applicability of the Valve Rule's revisions to § 192.615 could entail additional compliance burdens for affected gas gathering operators, some operators may already incorporate the required content in their pipelines' emergency planning and notification procedures; indeed, such procedures are precisely the sort of procedures 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 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—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 (as well as manage any resulting compliance costs).

V. Regulatory Analyses and Notices

A. Authority for This Rule

This proposed rule is published under the authority of the Secretary of Transportation delegated to the PHMSA Administrator pursuant to 49 CFR 1.97. Among the statutory authorities delegated to PHMSA are those set forth in the Federal Pipeline Safety Statutes (49 U.S.C. 60101 *et seq.*). 49 U.S.C. 60102 grants authority to issue standards for the transportation of gas via any part 192-regulated gathering pipelines to protect public safety and the environment; and 49 U.S.C. 60102(b)(5) specifies that PHMSA must consider both public safety and environmental benefits.

This NPRM proposes to implement several provisions of the PIPES Act of 2020, including those codified at 49 U.S.C. 60102, 60105, 60106, and 60109. Section 60102 authorizes the Secretary of Transportation to issue regulations governing the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of gas pipeline facilities, including gas transmission, gas distribution, offshore gas gathering, and Types A, B, and C gas gathering pipelines, each of which would be subject to various proposed requirements in this NPRM. Sections 60105 and 60106 permit States to assume safety authority over intrastate pipelines, including gas and hazardous liquid pipelines, and underground natural gas storage facilities through certifications or agreements with PHMSA, while section 60107 authorizes the Secretary to establish requirements governing award of grants supporting

[182] The severity of harms to public safety and the environment from a rupture on a gas pipeline depend (inter alia) on the volume of gas released, the duration of the release, and the time before mitigation/response actions are initiated and completed.

[183] 87 FR at 20949–52, 20972, 20972.

[184] 87 FR 20952–53.

[185] PHMSA understands that in so doing, the § 192.635 definition of ''notification of potential rupture'' referenced within § 192.3 would apply to all part 192-regulated gas gathering pipelines as well.

State pipeline safety programs. Additionally, 49 U.S.C. 60117 authorizes the Secretary of Transportation to direct operators of those gas pipeline facilities to submit reports to PHMSA to inform PHMSA's regulatory oversight activities. As described above, 49 U.S.C. 60102, 60105, and 60109 also require the Secretary to issue regulations updating PHMSA regulations in 49 CFR parts 192 and 198.

B. Executive Orders 12866 and 14094; DOT Regulatory Policies and Procedures

Executive Order 12866 (''Regulatory Planning and Review''), as amended by Executive Order 14094 (''Modernizing Regulatory Review''), requires that agencies ''should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating.'' [186] Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, Executive Order 12866 requires that agencies maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach. Similarly, DOT Order 2100.6A (''Rulemaking and Guidance Procedures'') requires that regulations issued by PHMSA and other DOT Operating Administrations should consider an assessment of the potential benefits, costs, and other important impacts of the proposed action and should quantify (to the extent practicable) the benefits, costs, and any significant distributional impacts, including any environmental impacts.

Executive Order 12866 (as amended by Executive Order 14094) and DOT Order 2100.6A require that PHMSA submit ''significant regulatory actions'' to the Office of Management and Budget (OMB) for review. The proposed rule has been determined to be significant under section 3(f) of Executive Order 12866 (as amended by section 1(b) of Executive Order 14094) and DOT Order 2100.6A and was reviewed by the Office of Information and Regulatory Affairs (OIRA) within OMB.

Consistent with Executive Order 12866 (as amended by Executive Order 14094) and DOT Order 2100.6A, PHMSA has prepared a PRIA assessing the benefits and costs of the proposed rule as well as reasonable alternatives. PHMSA estimates the proposed rule will result in unquantified public safety and environmental benefits associated with preventing and mitigating incidents on gas distribution and other part 192-regulated gas pipeline facilities. PHMSA estimates annualized costs of $110 million per year (using a 3 percent discount rate) due to costs associated with the proposed requirements for updating emergency response plans, updating O&M manuals, keeping records, gas monitoring by qualified employees, and assessing and upgrading district regulator stations. For the full cost/benefit analysis, please see the PRIA in the rulemaking docket. PHMSA seeks comment on the PRIA, its approach, and the accuracy of its estimated costs and benefits.

C. Environmental Justice

Executive Order 12898 (''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations''),[187] directs Federal agencies to take appropriate and necessary steps to identify and address disproportionately high and adverse effects of Federal actions on the health or environment of minority and low-income populations to the greatest extent practicable and permitted by law. DOT Order 5610.2C (''U.S. Department of Transportation Actions to Address Environmental Justice in Minority Populations and Low-Income Populations'') establishes departmental procedures for effectuating Executive Order 12898 promoting the principles of environmental justice through full consideration of environmental justice principles throughout planning and decision-making processes in the development of programs, policies, and activities—including PHMSA rulemaking.

PHMSA has evaluated this NPRM under DOT Order 5610.2C and Executive Order 12898 and has preliminarily determined it will not cause disproportionately high and adverse human health and environmental effects on minority and low-income populations. The proposed rule is facially neutral and national in scope; it is neither directed toward a particular population, region, or community, nor is it expected to result in any adverse environmental or health impact any particular population, region, or community. Rather, PHMSA anticipates the rulemaking will reduce the safety and environmental risks associated with losses of integrity on gas pipeline facilities—particularly gas distribution pipelines in urban or rural areas posing higher risks due to their vintage, material, and proximity to minority and low-income communities in the vicinity of those pipelines.[188] Lastly, as explained in the draft environmental assessment in the rulemaking docket, PHMSA anticipates that the regulatory amendments in this proposed rule will yield greenhouse gas emissions reductions, thereby reducing the risks posed by anthropogenic climate change to minority and low-income, populations, underserved and other disadvantaged communities. This finding is consistent with the most recent Environmental Justice Executive Order 14096—Revitalizing Our Nation's Commitment to Environmental Justice for All, by achieving several goals including continuing to deepen the Administration's whole of government approach to environmental justice and to better protect overburden communities from pollution and environmental harms.

D. Regulatory Flexibility Act

The Regulatory Flexibility Act, as amended by the Small Business Regulatory Flexibility Fairness Act of 1996 (5 U.S.C. 601 *et seq.*), generally requires Federal agencies to prepare an initial regulatory flexibility analysis (IRFA) for a proposed rule subject to notice-and-comment rulemaking under the Administrative Procedure Act. 5 U.S.C. 603(a).[189] Executive Order 13272 (''Proper Consideration of Small Entities in Agency Rulemaking'') [190] obliges agencies to establish procedures promoting compliance with the Regulatory Flexibility Act; DOT's implementing guidance is available on its website.[191]

This NPRM was developed in accordance with Executive Order 13272 and DOT guidance to ensure compliance with the Regulatory Flexibility Act and provide appropriate consideration of the potential impacts of the rulemaking on small entities. PHMSA conducted an IRFA, which has been made available in the docket for this rulemaking and is summarized below. A description of the reasons why

[186] E.O. 12866 is available at 58 FR 51735 (Oct. 4, 1993); E.O. 14094 is available at 88 FR 21879 (Apr. 6, 2023).

[187] 59 FR 7629 (Feb. 16, 1994).

[188] *See, e.g.,* Luna & Nicholas, ''An Environmental Justice Analysis of Distribution-Level Natural Gas Leaks in Massachusetts, USA,'' 162 Energy Policy 112778 (Mar. 2022); Weller et al., ''Environmental Injustices of Leaks from Urban Natural Gas Distribution Systems: Patterns Among and Within 13 U.S. Metro Areas,'' Environ. Sci & Tech. (May 11, 2022).

[189] Agencies are not required to conduct an IRFA if the head of the agency certifies that the proposed rule will not have a significant impact on a substantial number of small entities. 5 U.S.C. 605.

[190] 67 FR 53461 (Aug. 16, 2002).

[191] DOT, ''Rulemaking Requirements Concerning Small Entities'', *https://www.transportation.gov/regulations/rulemaking-requirements-concerning-small-entities* (last updated May 18. 2012).

PHMSA is considering this action and a succinct statement of the objectives of, and legal basis for, the proposed rule are described elsewhere in the preamble for this rule and not repeated here. PHMSA seeks comment on whether the proposed rule, if adopted, would have a significant economic impact on a significant number of small entities.

Description and Estimate of the Number of Small Entities to Which the Proposed Rule Would Apply

PHMSA analyzed privately owned entities (inclusive of investor-owned entities) that could be impacted by the rule, which include companies with natural gas extraction, pipeline transportation, and natural gas distribution businesses, as well as entities with another primary business. PHMSA determined whether these entities were small entities based on the size of the parent entity and using the relevant SBA size standards set out in Table 43 of the PRIA. PHMSA also analyzed publicly owned entities that could be impacted by the rule, including State, municipal, and other political subdivision entities. Publicly owned entities with population less than 50,000 are considered small.

PHMSA identified 1,239 gas distribution parent entities and determined that of these parent entities, 92 percent (1,135 parent entities) are classified as ''small'' based on the relevant criteria listed above. PHMSA also identified 831 gas transmission and gathering parent entities in this analysis that do not also operate distribution systems. Of these gas transmission and gas gathering parent entities, 82 percent are classified as ''small'' (681 parent entities). Because PHMSA did not have sufficient information to individually categorize master meter operators or operators of small LPGs by size, PHMSA conservatively made the over-inclusive decision to consider all master meter operators and operators of small LPGs to be small entities for purposes of its analysis.

Description of Projected Reporting, Recordkeeping, and Other Compliance Requirements of the Proposed Rule, Including an Estimate of the Classes of Small Entities Which Would Be Subject to the Requirement and the Type of Professional Skills Necessary for Preparation of the Report or Record

PHMSA analyzed the costs of compliance for the small gas distribution, gas transmission and gathering, and master meter and small LPG operators. PHMSA assessed the annualized cost for gas distribution operators based on the number of services, and provided a minimum, average, and maximum annualized cost estimate for each size category. For small gas distribution operators with 100,000 or fewer services, PHMSA calculated annualized estimated compliance costs that ranged from $8,051 to $10,528 depending on the cost scenario and discount rate.[192] For gas transmission and gathering operators, PHMSA calculated minimum, average, and maximum annualized estimated compliance costs that ranged from $44 to $52,029 depending on the cost scenario, industry type (transmission or gathering), and discount rate. For small master meter systems, PHMSA estimated pre-tax annualized compliance costs for individual operators from $4,421 to $4,590, depending on the discount rate. For small LPG systems, PHMSA estimated pre-tax annualized compliance costs for individual operators from $4,764 to $4,928, again depending on the discount rate.

PHMSA then calculated cost-to-revenue ratios using the calculated compliance costs of each small parent entity. PHMSA estimated that 98 percent of small gas distribution parent entities will face after-tax compliance costs of less than 1 percent of revenue under all evaluated cost scenarios. PHMSA estimated that 80 to 82 percent of small gas transmission parent entities operators will incur after-tax compliance costs of less than 1 percent of revenue. Under the maximum cost scenario, PHMSA estimates that 1 percent of small parent entities will incur compliance costs above 1 percent but below 3 percent of revenue. Under this maximum cost scenario, PHMSA also estimates that one small parent entity will incur compliance costs above 3 percent of revenue. However, PHMSA believes the maximum cost scenario is unlikely, as it assumes the entirety of estimated new and replaced lines are attributable to a single operator.[193] For master meter operators and operators of small LPGs, PHMSA calculated the break-even value of annual revenue that would be required for their calculated after-tax compliance costs to be 1 percent and 3 percent of revenue. For master meter operators, PHMSA estimated that revenue would need to be $442,122 or less for compliance costs to be 1 percent of revenue and that revenue would need to be $147,374 or less for compliance costs to be 3 percent of revenue. For operators of small LPGs, PHMSA estimated that revenue would need to be $476,357 or less for compliance costs to be 1 percent of revenue and that revenue would need to be $158,786 or less for compliance costs to be 3 percent of revenue.

[192] See PRIA Table 45.

[193] For the other 18% of operators, PHMSA did not have sufficient data to calculate the revenue percentage for the compliance costs of the rule at this time. PHMSA seeks comment on compliance costs generally, but in particular for transmission and gathering operators for which sufficient data was not available.

Relevant Federal Rules Which May Duplicate, Overlap or Conflict With the Proposed Rule

PHMSA did not identify any Federal rules that may duplicate, overlap, or conflict with the proposed rule. In Section 7.6 of the PRIA accompanying this NPRM, PHMSA provides details on other Federal regulations that may impact operators of gas pipelines.

Description and Analysis of Significant Alternatives to the Proposed Rule Considered

PHMSA analyzed a number of alternatives to the NPRM, which are described in detail in Section 2 of the PRIA accompanying this NPRM. In addition to retaining the status quo and not issuing the proposal, which PHMSA determined would fail to satisfy PIPES Act mandates to improve safety and update PHMSA regulations, PHMSA also analyzed:

1. Retaining DIMP requirements for small LPG operators and imposing the updated DIMP requirements of this NPRM on those same operators.
2. Extending to all part 192-regulated pipelines an exception that currently allows, for distribution mains only, distribution operator personnel involved in the same construction task to inspect each other's work.
3. An alternative compliance date.
4. Imposing an ICS requirement for emergency response.
5. Requiring all future construction projects associated with installations, modifications, replacements, or system upgrades on gas distribution pipelines to have licensed professional engineer approval and stamping.
6. Requiring gas distribution operators to develop and follow an MOC process as outlined in ASME/ANSI B31.8S.

PHMSA did not identify any viable alternative that could accomplish the stated objectives of applicable statutes while further minimizing any significant economic impact of the proposed rule on small entities. As discussed in more detail elsewhere in this preamble and in Section 2 of the PRIA for this NPRM, PHMSA determined that these requirements could result in reductions in safety benefits that were not justified by any potential cost savings (*e.g.,* the proposal to extend the exception for distribution mains that allows distribution operator personnel to inspect each other's work on the same construction task to all part-192 regulated pipelines) or impose costs on small entities that were not justified by any increased safety benefits. PHMSA therefore declined to propose these alternatives but seeks comment on them in this proposed rule.

E. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

PHMSA analyzed this proposed rule in accordance with the principles and criteria contained in Executive Order 13175 (''Consultation and Coordination with Indian Tribal Governments'') [194] and DOT Order 5301.1A (''Department of Transportation Programs, Policies, and Procedures Affecting American Indians, Alaska Natives, and Tribes''). Executive Order 13175 requires agencies to ensure meaningful and timely input from Tribal government representatives in the development of rules that significantly or uniquely affect Tribal communities by imposing ''substantial direct compliance costs'' or ''substantial direct effects'' on such communities, or the relationship or distribution of power between the Federal Government and Tribes.

PHMSA assessed the impact of the proposed rule and does not expect it will significantly or uniquely affect Tribal communities or Indian Tribal governments. The proposed rule's regulatory amendments are facially neutral and will have broad, national scope. PHMSA, therefore, does not expect this rule to significantly or uniquely affect Tribal communities, impose substantial compliance costs on Native American Tribal governments, or mandate Tribal action. And insofar as PHMSA expects the NPRM will improve safety and reduce environmental risks associated with gas distribution pipelines, PHMSA expects it will not entail disproportionately high adverse risks for Tribal communities. Therefore, PHMSA concludes that the funding and consultation requirements of Executive Order 13175 and DOT Order 5301.1A do not apply to this proposed rule.

While PHMSA is not aware of specific Tribal-owned business entities that operate part 192-regulated gas pipelines, any such business entities could be subject to direct compliance costs as a result of this proposed rule. PHMSA seeks comment on the applicability of Executive Order 13175 to this proposed rule and the existence of any Tribal-owned business entities operating pipelines affected by the proposed rule (along with the extent of such potential impacts).

F. Paperwork Reduction Act

Pursuant to 5 CFR 1320.8(d), PHMSA is required to provide interested members of the public and affected agencies with an opportunity to comment on information collection and recordkeeping requests. If adopted, the proposals in this rulemaking would impose new notification and recordkeeping requirements for all part 192-regulated pipelines, including gas distribution, gas transmission and gathering pipelines.

PHMSA proposes to require gas distribution operators to review their integrity management plans to ensure that the plans identify specific threats such as: (1) certain materials, such as cast iron and other piping with known issues, (2) the age of each component of the operator's pipelines along with the overall age of its system, (3) overpressurization of low-pressure systems, and (4) extreme weather and geohazards. PHMSA also proposes that, when identifying and implementing measures to address those risks, operators must address (at a minimum) the risks associated with each of the following: the presence of known issues, the age of each part of a pipeline along with the overall age of the system, and (for operators of low-pressure gas distribution systems) overpressurization. PHMSA plans to revise the ''Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines'' information collection that is currently approved under OMB Control No. 2137–0625 to include this new requirement. Since pipeline operators are already required to review and update their integrity management plans on a regular basis, PHMSA expects operators to incur minimal burden in complying with this information collection request.

PHMSA also proposes to repeal the requirement for operators of small LPGs to participate in the distribution integrity management program. Based on a recent study, PHMSA estimates there are as many as 4,492 small LPG operators. PHMSA proposes to create a new form, PHMSA Form 7100.1–2, to collect limited data from these operators of small LPGs on an annual basis. As a result, PHMSA expects the burden of the ''Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines'' information collection under OMB Control No. 2137–0625 to be reduced and the burden for information collection under OMB Control No. 2137–0522 for the collection of annual and incident report data to increase due to the creation of the new form. Specifically, PHMSA expects each small LPG operator to spend 6 hours, annually, completing the new report form, resulting in an increase of 4,492 responses and 26,952 hours to the overall burden for the information collection under OMB Control No. 2137–0522. For the information collection under OMB Control No. 2137–0625, PHMSA previously estimated there were 2,539 operators of small LPG systems. Consequently, PHMSA expects the burden of that currently approved collection to be reduced by 2,539 responses and 66,014 hours due to the removal of small LPG operators. PHMSA also plans to revise the ''Gas Distribution Annual Report Form F7100.1–1'' information collection currently approved under OMB Control No. 2137–0629 to include the newly proposed requirements. For gas distribution pipelines, PHMSA proposes to collect additional information such as the number and miles of low-pressure service pipelines, including their overpressure protection methods.

PHMSA proposes codifying within the pipeline safety regulations its State Inspection Calculation Tool (SICT). The SICT is one of many factors used to help states determine the base level amount of time needed for administering adequate pipeline safety programs and is a consideration when PHMSA awards grants to states supporting those programs. PHMSA plans to revise the ''Gas Pipeline Safety Program Performance Progress Report'' and ''Hazardous Liquid Pipeline Safety Program Performance Progress Report'' information collection currently approved under OMB Control No. 2137–0584 to account for the burden incurred by state representatives to report data via the SICT.

Operators are required to maintain records pertaining to various aspects of their pipeline systems. Under the proposals in this rulemaking, PHMSA would expand the recordkeeping requirements for all gas pipeline operators. Operators would be required to revise their emergency response plans to include procedures ensuring prompt and effective response by adding emergencies involving a release of gas that results in a fatality, as well as any other emergency deemed significant by the operator. In the event of a release of gas resulting in one or more fatalities, all operators would also be required to immediately and directly notify emergency response officials upon receiving notice of the same. For distribution pipeline operators only,

[194] 65 FR 67249 (Nov. 6, 2000).

PHMSA's proposed expansion of the list of emergencies discussed above would also include the unintentional release of gas and shutdown of gas service to 50 or more customers (or 50 percent of its customers if it has fewer than 100 total customers). Operators would need to immediately and directly notify emergency response officials on receiving notice of the same.

PHMSA also proposes a series of regulatory amendments requiring gas distribution operators to update their emergency response plans to improve communications with the public during an emergency. First, PHMSA proposes to introduce a new requirement for gas distribution operators to establish and maintain communications with the general public as soon as practicable during an emergency. Second, PHMSA proposes to add a new requirement for gas distribution pipeline operators to develop and implement, no later than 18 months after the publication of any final rule in this proceeding, an opt-in system to keep their customers informed of the status of pipeline safety in their communities should an emergency occur. PHMSA also proposes a new requirement for gas distribution operators to notify their customers and public officials in certain instances. PHMSA plans to create a new information collection to cover these notification requirements for gas distribution operators. PHMSA will request a new Control Number from OMB for these information collections. PHMSA will submit these information collection requests to OMB for approval based on the proposed requirements in this rule.

Operators would also be required to review and update their O&M manuals as needed pursuant to the proposal. Gas distribution operators would also be required to document and maintain records on their MOC processes and additional safety procedures. Further, PHMSA proposes that all gas distribution pipeline operators identify and maintain traceable, verifiable, and complete maps and records documenting the characteristics of their systems that are critical to ensuring proper pressure controls for their gas distribution pipeline systems and to ensure that those records are accessible to anyone performing or supervising design, construction, and maintenance activities on their systems. PHMSA proposes to specify that these required records include (1) the maps, location, and schematics related to underground piping, regulators, valves, and control lines; (2) regulator set points, design capacity, and valve-failure mode (open/closed); (3) the system's overpressure-protection configuration; and (4) any other records deemed critical by the operator. PHMSA proposes to require that the operator maintain these integrity-critical records for the life of the pipeline because these records are critical to the safe operation and pressure control of a gas distribution system. PHMSA plans to revise the ''Recordkeeping Requirements for Gas Pipeline Operators'' information collection currently approved under OMB Control No. 2137–0049 to include the newly proposed recordkeeping requirements. PHMSA expects the impact to be minimal and absorbed by the currently approved burden for this information collection.

The information collections in this proposed rule would be required through the proposed amendments to the pipeline safety regulations, 49 CFR 190–199. The following information is provided for each information collection: (1) Title of the information collection; (2) OMB control number; (3) Current expiration date; (4) Type of request; (5) Abstract of the information collection activity; (6) Description of affected public; (7) Estimate of total annual reporting and recordkeeping burden; and (8) Frequency of collection. The information collection burden under the proposed rule is estimated as follows:

1. *Title:* Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines.

OMB Control Number: 2137–0625.

Current Expiration Date: 5/31/2024.

Abstract: The pipeline safety regulations require operators of gas distribution pipelines to develop and implement integrity management (IM) programs. The purpose of these programs is to enhance safety by identifying and reducing pipeline integrity risks. PHMSA requires operators to maintain records demonstrating compliance with this information collection for 10 years. PHMSA uses the information to evaluate the overall effectiveness of gas distribution Integrity Management requirements.

PHMSA proposes to repeal the requirement for operators of small LPGs to participate in the distribution IM program. PHMSA previously estimated that there were 2,539 operators of small LPG systems. Consequently, PHMSA expects the burden of this information collection to be reduced by 2,539 responses and 66,014 hours due to the removal of small LPG operators.

Affected Public: Owners and operators of gas distribution pipelines.

Annual Reporting Burden:

Total Annual Responses: 1,343.

Total Annual Burden Hours: 657,178.

Frequency of Collection: On occasion.

2. *Title:* Recordkeeping Requirements for Gas Pipeline Operators.

OMB Control Number: 2137–0049.

Current Expiration Date: 3/31/2025.

Abstract: This mandatory information collection request would require owners and/or operators of gas pipeline systems to make and maintain records in accordance with the requirements prescribed in 49 CFR part 192 and to provide information to the Secretary of Transportation at the Secretary's request. Certain records are maintained for a specific length of time while others are required to be maintained for the life of the pipeline. PHMSA uses these records to verify compliance with regulated safety standards and to inform the agency on possible safety risks.

Affected Public: Operators of gas pipeline systems.

Annual Reporting Burden:

Total Annual Responses: 4,056,052.

Total Annual Burden Hours: 5,031,086.

Frequency of Collection: On occasion.

3. *Title:* Emergency Notification Requirements for Gas Operators.

OMB Control Number: Will Request from OMB.

Current Expiration Date: TBD.

Abstract: This information collection covers the requirement for owners and operators of gas distribution pipelines to notify their customers and public officials in the event of certain instances pertaining to pipeline safety. PHMSA estimates there will be an average of 75 incidents per year where gas distribution operators will need to make such notifications. PHMSA expects gas distribution operators will spend approximately 8 hours notifying the public in each instance, resulting in an annual burden of 600 hours. PHMSA expects gas distribution operators to spend an additional 2 hours per incident notifying their customers, resulting in an added burden of 150 hours. PHMSA also requires operators of all gas pipelines to notify and communicate with emergency responders if gas is detected inside or near a building; fire is located near or directly involving a pipeline facility; and explosion occurs near or directly involving a pipeline facility; or in the event of a natural disaster. Based on incident report trends, PHMSA expects there to be 44 incidents (1 gas gathering, 16 gas transmission, 27 gas distribution) annually, which would require gas operators to notify emergency responders. PHMSA estimates each notification will take 2 hours per incident resulting in an annual burden of 88 hours.

Affected Public: Owners and operators of gas pipelines.

Annual Reporting Burden:

Total Annual Responses: 194.

Total Annual Burden Hours: 838.

Frequency of Collection: On occasion.

4. *Title:* Annual and Incident Report for Gas Pipeline Operators.

OMB Control Number: 2137–0522.

Current Expiration Date: 03/31/2026.

Abstract: This mandatory information collection covers the collection of data from operators of natural gas pipelines, underground natural gas storage facilities, and liquefied natural gas (LNG) facilities for annual reports. 49 CFR 191.17 requires operators of underground natural gas storage facilities, gas transmission systems, and gas gathering systems to submit an annual report by March 15 for the preceding calendar year. The Gas Distribution NPRM proposes to collect limited data from operators of small LPGs. PHMSA proposes to create Form F7100.1–2. to collect this data, ''Small LPG Annual Report Form F7100.1–2.'' The burden for this information collection is being revised to account for this new data collection. PHMSA estimates that 4,492 small LPG operators will spend 6 hours annually completing this new report resulting in an increase of 4,492 responses and 26,952 hours to the currently approved burden for this information collection.

Affected Public: Owners and operators of gas distribution pipelines.

Annual Reporting Burden:

Total Annual Responses: 7,813.

Total Annual Burden Hours: 122,763.

Frequency of Collection: Annually.

5. *Title:* Gas Pipeline Safety Program Performance Progress Report and Hazardous Liquid Pipeline Safety Program Performance Progress Report.

OMB Control Number: 2137–0584.

Current Expiration Date: 5/31/2025.

Abstract: 49 U.S.C. 60105 sets forth specific requirements a State must meet to qualify for certification status to assume regulatory and enforcement responsibility for intrastate pipelines, *i.e.,* state adoption of minimum Federal safety standards, state inspection of pipeline operators to determine compliance with the standards, and state provision for enforcement sanctions substantially the same as those authorized by Chapter 601, Title 49 of the U.S. Code. A State must submit an annual certification to assume responsibility for regulating intrastate pipelines, and states who receive Federal grant funding must have adequate damage prevention plans and associated records in place. PHMSA uses this information to evaluate a State's eligibility for Federal grants and to enforce regulatory compliance. This information collection request requires a participating State to annually submit a Gas Pipeline Safety Program Performance Progress Report and Hazardous Liquid Pipeline Safety Program Performance Progress Report to PHMSA's Office of Pipeline Safety (OPS) signifying compliance with the terms of the certification and to maintain records detailing a damage prevention plan for PHMSA inspectors whenever requested. The purpose of the collection is to exercise oversight of the grant program and to ensure that States are compliant with Federal pipeline safety regulations. PHMSA is revising this information collection to include the reporting of inspection data via the State Inspection Calculation Tool (SICT). PHMSA expects 66 State representatives to submit data pertaining to the number of safety inspectors employed in their pipeline safety programs via the SICT. PHMSA estimates that, on average, State representatives will spend 8 hours annually compiling and submitting SICT data.

Affected Public: Pipeline operators applying for State grants.

Annual Reporting Burden:

Total Annual Responses: 183.

Total Annual Burden Hours: 5,001.

Frequency of Collection: Annual.

6. *Title:* Annual for Gas Distribution Operators.

OMB Control Number: 2137–0629.

Current Expiration Date: 06/30/2026.

Abstract: This mandatory information collection request would require operators of gas distribution pipeline systems to submit annual report data to the Office of Pipeline Safety in accordance with the regulations stipulated in 49 CFR part 191 by way of form PHMSA F 7100.1–1. The form is to be submitted once for each calendar year. The annual report form collects data about the pipe material, size, and age. The form also collects data on leaks from these systems as well as excavation damages. PHMSA uses the information to track the extent of gas distribution systems and normalize incident and leak rates.

The Gas Distribution NPRM proposes to revise the Annual Report for Gas Distribution Operators, form PHMSA F 7100.1–1, to collect additional information on gas distribution systems such as the number and miles of low-pressure service pipelines, including their overpressure protection methods.

The current approved burden for gas distribution operators to complete this report is 20 hours, annually. As a result of the proposed change, the burden for completing PHMSA F 7100.1-collection is being increased by 6 hours annually, resulting in an overall burden of 26 hours, per annual report, for gas distribution operators.

Affected Public: Owners and operators of gas distribution pipelines.

Annual Reporting Burden:

Total Annual Responses: 1,446.

Total Annual Burden Hours: 37,596.

Frequency of Collection: Annually.

Requests for a copy of these information collections should be directed to Angela Hill via email at *angela.hill@dot.gov* or via telephone (202) 366–4595.

Comments are invited on:

(a) The need for the proposed collection of information for the proper performance of the functions of the agency, including whether the information will have practical utility;

(b) The accuracy of the agency's estimate of the burden of the revised collection of information, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected;

(d) Ways to minimize the burden of the collection of information on those who are to respond, including the use of appropriate automated, electronic, mechanical, or other technological collection techniques; and

(e) Ways the collection of this information is beneficial or not beneficial to public safety.

Send comments directly to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attn: Desk Officer for the Department of Transportation, 725 17th Street NW, Washington, DC 20503.

G. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (UMRA, 2 U.S.C. 1501 *et seq.*) requires agencies to assess the effects of Federal regulatory actions on State, local, and Tribal governments, and the private sector. For any NPRM or final rule that includes a Federal mandate that may result in the expenditure by State, local, and Tribal governments, in the aggregate of $100 million or more (in 1996 dollars) in any given year, the agency must prepare, amongst other things, a written statement that qualitatively and quantitatively assesses the costs and benefits of the Federal mandate.

As explained further in the PRIA, PHMSA does not expect that the proposed rule will impose enforceable duties on State, local, or Tribal governments or on the private sector of $100 million or more (in 1996 dollars) in any one year. A copy of the PRIA is available for review in the docket. Therefore, the requirement to prepare a statement pursuant to UMRA does not apply.

H. National Environmental Policy Act

The National Environmental Policy Act of 1969 (NEPA, 42 U.S.C. 4321 *et seq.*) requires Federal agencies to prepare a detailed statement on major Federal actions significantly affecting the quality of the human environment. The Council on Environmental Quality's implementing regulations (40 CFR parts 1500–1508) require Federal agencies to conduct an environmental review considering (1) the need for the action, (2) alternatives to the action, (3) probable environmental impacts of the action and alternatives, and (4) the agencies and persons consulted during the consideration process. DOT Order 5610.1C (''Procedures for Considering Environmental Impacts'') establishes departmental procedures for evaluation of environmental impacts under NEPA and its implementing regulations.

PHMSA has completed a draft environmental assessment and expects that an environmental impact statement will not be required for this rulemaking because it will not have a significant impact on the human environment. To the extent that the proposed rule could impact the environment, PHMSA expects those impacts will be primarily beneficial impacts from reducing the likelihood and consequences of incidents on gas distribution pipelines and other part 192-regulated gas pipelines. A copy of the draft environmental assessment is available in the docket. PHMSA invites comment on the potential environmental impacts of this proposed rule.

I. Executive Order 13132: Federalism

PHMSA has analyzed this proposed rule in accordance with the principles and criteria contained in Executive Order 13132 (''Federalism'') [195] and the Presidential Memorandum titled ''Preemption.'' [196] Executive Order 13132 requires agencies to ensure meaningful and timely input by State and local officials in the development of regulatory policies that may have ''substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.''

PHMSA does not expect this proposed rule will have a substantial direct effect on State and local governments, the relationship between the Federal Government and the States, or the distribution of power and responsibilities among the various levels of government. The provisions proposed involving SICT codify in regulation existing practice and do not impose any noteworthy additional direct compliance costs on State and local governments.

States are generally prohibited by 49 U.S.C. 60104(c) from regulating the safety of interstate pipelines. States that have submitted a current certification under 49 U.S.C. 60105(a) can augment Federal pipeline safety requirements for intrastate pipelines regulated by PHMSA but may not approve safety requirements less stringent than those required by Federal law. A State may also regulate an intrastate pipeline facility that PHMSA does not regulate.

In this instance, the preemptive effect of the proposed rule would be limited to the minimum level necessary to achieve the objectives of the statutory authority under which the proposed rule is promulgated. While the 49 CFR part 192 safety requirements in this proposed rule may, if adopted in a final rule, preempt some State requirements, preemption arises by operation of 49 U.S.C. 60104, and this proposed rule would not impose any regulation that has substantial direct effects on the states, the relationship between the national government and the states, or the distribution of power and responsibilities among the various levels of government. Therefore, the PHMSA has determined that the consultation and funding requirements of Executive Order 13132 do not apply to this proposed rule.

J. Executive Order 13211: Significant Energy Actions

Executive Order 13211 (''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'') [197] requires Federal agencies to prepare a Statement of Energy Effects for any ''significant energy action.'' Executive Order 13211 defines a ''significant energy action'' as any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation that (1)(i) is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) is designated by OIRA as a significant energy action.

This proposed rule is not anticipated to be a ''significant energy action'' under Executive Order 13211. It is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, the OIRA has not designated this proposed rule as a significant energy action.

K. Privacy Act Statement

In accordance with 5 U.S.C. 553(c), DOT solicits comments from the public to better inform its rulemaking process. DOT posts these comments without edit, including any personal information the commenter provides, to *https://www.regulations.gov,* as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *https://www.dot.gov/privacy.*

L. Regulation Identifier Number

A regulation identifier number (RIN) is assigned to each regulatory action listed in the Unified Agenda of Regulatory and Deregulatory Actions (Unified Agenda). The RIN contained in the heading of this document can be used to cross-reference this action with the Unified Agenda.

M. Executive Order 13609 and International Trade Analysis

Executive Order 13609 (''Promoting International Regulatory Cooperation'') [198] requires agencies to consider whether the impacts associated with significant variations between domestic and international regulatory approaches are unnecessary or may impair the ability of American business to export and compete internationally. In meeting shared challenges involving health, safety, labor, security, environmental, and other issues, international regulatory cooperation can identify approaches that are at least as protective as those that are or would be adopted in the absence of such cooperation. International regulatory cooperation can also reduce, eliminate, or prevent unnecessary differences in regulatory requirements.

Similarly, the Trade Agreements Act of 1979 (Pub. L. 96–39), as amended by the Uruguay Round Agreements Act (Pub. L. 103–465), prohibits Federal agencies from establishing any standards or engaging in related activities that create unnecessary obstacles to the foreign commerce of the United States. For purposes of these requirements, Federal agencies may participate in the establishment of international standards so long as the standards have a legitimate domestic objective, such as providing for safety,

[195] 64 FR 43255 (Aug. 10, 1999).

[196] 74 FR 24693 (May 22, 2009).

[197] 66 FR 28355 (May 22, 2001).

[198] 77 FR 26413 (May 4, 2012).

and do not operate to exclude imports that meet this objective. The statute also requires consideration of international standards and, where appropriate, that they serve as the basis for U.S. standards. PHMSA participates in the establishment of international standards to protect the safety of the American public.

PHMSA assessed the effects of the proposed rule and expects that it will not cause unnecessary obstacles to foreign trade.

N. Cybersecurity and Executive Order 14028

Executive Order 14028 (''Improving the Nation's Cybersecurity'') [199] directed the Federal government to improve its efforts to identify, deter, and respond to ''persistent and increasingly sophisticated malicious cyber campaigns.'' Accordingly, PHMSA has assessed the effects of this NPRM to determine what impact the proposed regulatory amendments may have on cybersecurity risks for pipeline facilities and has preliminarily determined that this NPRM will not materially affect the cybersecurity risk profile for pipeline facilities.

Operator DIMPs, O&M manuals and procedures, and facility design standards are largely static materials; because those materials are not means of manipulating pipeline operations in real-time, PHMSA's proposed amendments of requirements governing those materials are therefore unlikely to increase the risk of cybersecurity incidents. Although other proposals within the NPRM—in particular, real-time overpressurization monitoring and customer opt-in/opt-out emergency communication systems—may offer more attractive targets for cybersecurity incidents, PHMSA understands the incremental additional risk from the NPRM's proposed regulatory amendments to be minimal. Operator compliance strategies for these proposed requirements will be subject to current Transportation Security Agency (TSA) pipeline cybersecurity directives; [200] PHMSA further understands Cybersecurity & Infrastructure Security Agency (CISA) and the Pipeline Cybersecurity Initiative (PCI) of the U.S. Department of Homeland Security conduct ongoing activities to address cybersecurity risks to U.S. pipeline infrastructure and may introduce other cybersecurity requirements and guidance for gas pipeline operators.[201] Lastly, because PHMSA expects that this NPRM's proposed regulatory amendments (notably those regarding emergency response planning) will reduce the severity of any gas pipeline incidents that occur, this rulemaking could reduce the public safety and the environmental consequences in the event of a cybersecurity incident on a gas pipeline.

M. Severability

The purpose of this proposed rule is to operate holistically in addressing a panoply of issues necessary to ensure safe operation of regulate pipelines, with a focus on gas distribution pipelines' protection against overpressurization events. However, PHMSA recognizes that certain provisions focus on unique topics. Therefore, PHMSA preliminarily finds that the various provisions of this proposed rule are severable and able to function independently if severed from each other. In the event a court were to invalidate one or more of the unique provisions of any final rule issued in this proceeding, the remaining provisions should stand, thus allowing their continued effect.

List of Subjects

49 CFR Part 191

Liquefied petroleum gas, Pipeline reporting requirements.

49 CFR Part 192

District regulator stations, Emergency response, Gas monitoring, Integrity management, Inspections, Gas, Overpressure protection, Pipeline safety, Reporting and recordkeeping requirements.

49 CFR Part 198

State inspector staffing requirements.

For the reasons provided in the preamble, PHMSA proposes to amend 49 CFR parts 191, 192, and 198 as follows:

PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE; ANNUAL, INCIDENT, AND OTHER REPORTING

■ 1. The authority citation for 49 CFR part 191 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3); 49 U.S.C. 5121, 60101 *et seq.,* and 49 CFR 1.97.

■ 2. Revise § 191.11 to read as follows:

§ 191.11 Distribution system: Annual report.

(a) *General.* Except as provided in paragraph (b) of this section, each operator of a distribution pipeline system, excluding a liquefied petroleum gas system that serves fewer than 100 customers from a single source, must submit an annual report for that system on DOT Form PHMSA F 7100.1–1. Each operator of a liquefied petroleum gas system that serves fewer than 100 customers from a single source must submit an annual report for that system on DOT Form PHMSA F 7100.1–2. Reports must be submitted each year, not later than March 15, for the preceding calendar year.

(b) *Not required.* The annual report requirement in this section does not apply to a master meter system, a petroleum gas system excepted from part 192 in accordance with § 192.1(b)(5), or an individual service line directly connected to a production pipeline or a gathering line other than a regulated gathering line as determined in § 192.8.

PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

■ 3. The authority citation for 49 CFR part 192 continues to read as follows:

Authority: 30 U.S.C. 185(w)(3), 49 U.S.C. 5103, 60101 *et seq.,* and 49 CFR 1.97.

§ 192.3 [Amended]

■ 4. Amend § 192.3, by removing the last sentence ''This definition does not apply to any gathering line.'' from the definitions of ''Entirely replaced onshore transmission pipeline segments'', ''Notification of potential rupture'' and ''Rupture-mitigation valve (RMV)''.

§ 192.9 [Amended]

■ 5. Amend § 192.9 by:
■ a. Removing from paragraph (b) the last sentence;
■ b. Removing from paragraph (c) the last sentence; and
■ c. Removing from paragraph (e)(1)(iv) the words ''effective as of October 4, 2022.''
■ 6. Amend § 192.18 by revising paragraph (c) to read as follows:

§ 192.18 How to notify PHMSA.

* * * * *

(c) Unless otherwise specified, if an operator submits, pursuant to §§ 192.8, 192.9, 192.13, 192.179, 192.319, 192.506, 192.607, 192.619, 192.624, 192.632, 192.634, 192.636, 192.710, 192.712, 192.714, 192.745, 192.917, 192.921, 192.927, 192.933, 192.937, or

[199] 86 FR 26633 (May 17, 2021).

[200] *E.g.,* TSA, ''Ratification of Security Directive,'' 86 FR 38209 (July 20, 2021) (ratifying TSA Security Directive Pipeline–2012–01, which requires certain pipeline owners and operators to conduct actions to enhance pipeline cybersecurity).

[201] *See, e.g.,* CISA, National Cyber Awareness System Alerts, *https://www.cisa.gov/uscert/ncas/alerts* (last accessed Feb. 1, 2023).

192.1007, a notification for use of a different integrity assessment method, analytical method, compliance period, sampling approach, pipeline material, or technique (*e.g.,* ''other technology'' or ''alternative equivalent technology'') than otherwise prescribed in those sections, that notification must be submitted to PHMSA for review at least 90 days in advance of using the other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submitting the notification unless it receives a letter from the Associate Administrator for Pipeline Safety, or his or her delegate, informing the operator that PHMSA objects to the proposal or that PHMSA requires additional time and/or more information to conduct its review.

■ 7. Amend § 192.195 by adding paragraph (c) to read as follows:

§ 192.195 Protection against accidental overpressuring.

* * * * *

(c) *Additional requirements for low-pressure distribution systems.* Each regulator station, serving a low-pressure distribution system, that is new, replaced, relocated, or otherwise changed after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] must include:

(1) At least two methods of overpressure protection (such as a relief valve, monitoring regulator, or automatic shutoff valve) appropriate for the configuration and siting of the station;

(2) Measures to minimize the risk of overpressurization of the low-pressure distribution system that could be caused by any single event (such as excavation damage, natural forces, equipment failure, or incorrect operations), that either immediately or over time affects the safe operation of more than one overpressure protection device; and

(3) Remote monitoring of gas pressure at or near the location of overpressure protection devices.

■ 8. Amend § 192.305 by:
■ a. Lifting the stay of the section; and
■ b. Revising the section.

The revision reads as follows:

§ 192.305 Inspections: General.

(a) Each transmission pipeline and main that is new, replaced, relocated, or otherwise changed after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] must be inspected to ensure that it is constructed in accordance with this subpart. Except as provided in paragraph (b) of this section, an operator must not use operator personnel to perform a required inspection if the operator personnel performed the construction task requiring inspection. Nothing in this section prohibits the operator from inspecting construction tasks with operator personnel who are involved in other construction tasks.

(b) For the construction inspection of a main that is new, replaced, relocated, or otherwise changed after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], operator personnel involved in the same construction task may inspect each other's work in situations where the operator could otherwise only comply with the construction inspection requirement in paragraph (a) of this section by using a third-party inspector. This justification must be documented and retained for the life of the pipeline.

■ 9. Amend § 192.517 by revising paragraph (b) to read as follows:

§ 192.517 Records.

* * * * *

(b) Each operator must maintain a record of each test required by §§ 192.509, 192.511, and 192.513 for the life of the pipeline.

(1) For tests performed before [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE] for which records are maintained, the record must continue to be maintained for the life of the pipeline.

(2) For tests performed on or after [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], the records must contain at least the following information:

(i) The operator's name, the name of the employee responsible for making the test, and the name of the company or contractor used to perform the test.

(ii) Pipeline segment pressure tested.

(iii) Test date.

(iv) Test medium used.

(v) Test pressure.

(vi) Test duration.

(vii) Leaks and failures noted and their disposition.

■ 10. Amend § 192.605 by adding paragraphs (b)(13), (f), and (g) to read as follows:

§ 192.605 Procedural manual for operations, maintenance, and emergencies.

* * * * *

(b) * * *

(13) Implementing the applicable requirements for distribution systems in paragraphs (f) and (g) of this section, § 192.638, and § 192.640.

* * * * *

(f) *Overpressurization.* For distribution lines, the manual required by paragraph (a) of this section must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], include procedures for responding to, investigating, and correcting, as soon as practicable, the cause of overpressurization indications. The procedures must include the specific actions and an order of operations for immediately reducing pressure in or shutting down portions of the distribution system affected by an overpressurization.

(g) *Management of Change (MOC) Process.* For distribution lines, the manual required by paragraph (a) of this section must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], include a detailed MOC process for the following:

(1) Technology, equipment, procedural, and organizational changes, including:

(i) Installations, modifications, replacements, or upgrades to regulators, pressure monitoring locations, or overpressure protection devices;

(ii) Modifications to alarm set points or upper/lower trigger limits on monitoring equipment;

(iii) The introduction of new technologies for overpressure protection into the system;

(iv) Revisions, changes, or the introduction of new standard operating procedures for design, construction, installation, maintenance, and emergency response;

(v) Other changes that may impact the integrity or safety of the gas distribution system.

(2) Ensuring that personnel—such as an engineer with a professional engineer license, a subject matter expert, or another person who possesses the necessary knowledge, experience, and skills regarding gas distribution systems—review and certify construction plans associated with installations, modifications, replacements, or system upgrades for accuracy and completeness before the work begins. These personnel must be qualified to perform these tasks under subpart N of this part.

(3) Ensuring that any hazards introduced by a change are identified, analyzed, and controlled before resuming operations.

■ 11. Amend § 192.615 by:
■ a. Adding paragraphs (a)(3)(v) through (viii);
■ b. Revising paragraph (a)(8); and
■ c. Adding paragraphs (a)(13) and paragraph (d).

The additions and revision read as follows:

§ 192.615 Emergency plans.

(a) * * *

(3) * * *

(v) Notification of potential rupture (see § 192.635).

(vi) Beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], release of gas that results in one or more fatalities.

(vii) Beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], for distribution line operators only, unintentional release of gas and shutdown of gas service to 50 or more customers or, if the operator has fewer than 100 customers, 50 percent or more of its total customers.

(viii) Beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], any other emergency deemed significant by the operator.

* * * * *

(8) Notifying the appropriate public safety answering point (*i.e.,* 9–1–1 emergency call center) where direct access to a 9–1–1 emergency call center is available from the location of the pipeline, and fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information to determine the location of the emergency, including both planned responses and actual responses during an emergency. The operator must immediately and directly notify the appropriate public safety answering point or other coordinating agency for the communities and jurisdictions in which the pipeline is located after receiving notice of a gas pipeline emergency under paragraph (a)(3) of this section. The operator must coordinate and share information to determine the location of any release, regardless of whether the segment is subject to the requirements of §§ 192.179, 192.634, or 192.636.

* * * * *

(13) For distribution line operators, beginning no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE FINAL RULE], establishing and maintaining communication with the general public in the operator's service area as soon as practicable during a gas pipeline emergency on a distribution line. The communication(s) must be in English, and any other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's service area; be in one or more formats or media accessible to the population in the operator's service area; continue through service restoration and recovery efforts; and provide the following:

(i) Information regarding the gas pipeline emergency;

(ii) The status of the emergency (*e.g.,* have the condition causing the emergency or the resulting public safety risks been resolved);

(iii) Status of pipeline operations affected by the gas pipeline emergency, and when possible, a timeline for expected service restoration; and

(iv) Directions for the public to receive assistance.

The operator must provide updates when the information in § 192.615(a)(13)(i) through (iv) changes.

* * * * *

(d) No later than [DATE 18 MONTHS AFTER THE PUBLICATION DATE OF THE RULE], each distribution line operator must develop and implement a system, including written procedures, that allows operators to rapidly communicate with customers in the event of a gas pipeline emergency under this section. The notification system must be voluntary for the public, allowing customers to opt-in (or opt-out) to receiving notifications from the system. The written procedures must provide for the following:

(i) A description of the notification system and how it will be used to notify customers of a gas pipeline emergency;

(ii) Who is responsible for the development, operation, and maintenance of the system;

(iii) How information on the system is delivered to customers, ensuring that all customers are notified of the existence of the system and necessary steps if they wish to opt-in (or opt-out);

(iv) Description of the system-wide testing protocol, including the testing interval (which must not be less than once per calendar year), to ensure the system is functioning properly and performing notifications as designed;

(v) Maintenance of the results of testing and operations history for at least 5 years;

(vi) Details regarding how the operator ensures messages are accessible in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area;

(vii) Message content, including updates as emergency conditions change;

(viii) A process to initiate, conduct, and complete notifications; and

(ix) Cybersecurity measures to protect the system and customer information.

■ 12. Add § 192.638 to read as follows:

§ 192.638 Distribution lines: Records for pressure controls.

(a) An operator of a distribution system, except those identified in paragraph (f) of this section, must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], identify and maintain traceable, verifiable, and complete records that document the characteristics of its pipeline system that are critical to ensuring proper pressure control. These records must include:

(1) Current location information (including maps and schematics) for regulators, valves, and underground piping (including control lines);

(2) Attributes of the regulator(s), such as set points, design capacity, and the valve failure position (open/closed);

(3) The overpressure protection configuration; and

(4) Other records deemed critical.

(b) If an operator does not have traceable, verifiable, and complete records as required by paragraph (a) of this section, the operator must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], identify and document those records needed and develop and implement procedures for collecting those records.

(c) The records identified in paragraph (a) of this section must be collected, generated, or updated on an opportunistic basis, as specified in § 192.1007(a)(3).

(d) An operator must ensure the records required by this section are accessible to all personnel responsible for performing or supervising design, construction, operations, and maintenance activities.

(e) An operator must retain the records required in this section for the life of the pipeline.

(f) Exception. This section does not apply to master meter systems, liquefied petroleum gas (LPG) distribution pipeline systems that serve fewer than 100 customers from a single source, or any individual service line directly connected to a transmission, gathering, or production pipeline that is not operated as part of a distribution system.

■ 13. Add § 192.640 to read as follows:

§ 192.640 Distribution lines: Presence of qualified personnel.

(a) An operator of a distribution system must conduct a documented evaluation of each construction project that begins after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] to identify any potential project activities during which an overpressurization could occur at a district regulator station. This evaluation must occur before such activities begin. Activities that may present a potential for overpressurization include, but are not limited to, tie-ins, abandonment of distribution lines, and equipment replacement.

(b) If the evaluation in paragraph (a) of this section results in a determination that a potential for overpressurization exists during construction project activity, the operator must:

(1) Ensure that at least one person qualified according to subpart N of this part is present at that district regulator station, or at an alternative site, during the construction project activity that could cause an overpressurization;

(2) Monitor gas pressure with equipment capable of ensuring proper pressure controls; and

(3) Have the capability to promptly shut off the flow of gas or control overpressurization at a district regulator station.

(c) When monitoring the system as described in this section, the qualified personnel must be provided, at a minimum: information regarding the location of all valves necessary for isolating the pipeline system; pressure control records (see § 192.638); the authority to stop work (unless prohibited by operator procedures); operations procedures under § 192.605; and emergency response procedures under § 192.615.

(d) Exception. Distribution systems with a remote monitoring system in effect with the capability for remote or automatic shutoff need not comply with the requirements in paragraphs (a) through (c) of this section.

■ 14. Amend § 192.725 by revising paragraph (a) to read as follows:

§ 192.725 Test requirements for reinstating service lines.

(a) Except as provided in paragraph (b) of this section, each disconnected service line being restored to service on or after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE] must be tested in the same manner as a new service line (*i.e.,* tested in accordance with subpart J of this part) before being restored to service.

* * * * *

■ 15. Amend § 192.741 by:

■ a. Revising the title of the section, and

■ b. Adding paragraph (d).

The revision and addition read as follows:

§ 192.741 Pressure limiting and regulating stations: Telemetering, recording gauges, and other monitoring devices.

* * * * *

(d) On low-pressure distribution systems that are new, replaced, relocated, or otherwise changed after [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], the operator must monitor the gas pressure in accordance with § 192.195(c)(3).

§ 192.1001 [AMENDED]

■ 16. Amend § 192.1001 by removing the definition of ''Small LPG Operator.''

■ 17. Amend § 192.1003 by adding paragraph (b)(4) to read as follows:

§ 192.1003 What do the regulations in this subpart cover?

* * * * *

(b) * * *

(4) A system of a liquefied petroleum gas (LPG) distribution pipeline that serves fewer than 100 customers from a single source.

■ 18. Amend § 192.1005 by revising the title of the section to read as follows:

§ 192.1005 What must a gas distribution operator do to implement this subpart?

■ 19. Amend § 192.1007 by revising paragraphs (a)(3), (b), (c), and (d) to read as follows:

§ 192.1007 What are the required elements of an integrity management plan?

* * * * *

(a) * * *

(3) Identify additional information needed and provide a plan for obtaining that information over time (including the records specified in § 192.638(c)) through normal activities conducted on the pipeline (for example, design, construction, operations, or maintenance activities).

* * * * *

(b) *Identify threats.* The operator must consider the following categories of threats to each gas distribution pipeline: corrosion (including atmospheric corrosion); natural forces (including extreme weather, land movement, and other geological hazards); excavation damage; other outside force damage; material (including the presence and age of pipes such as cast iron, bare steel, unprotected steel, wrought iron, and historic plastics with known issues) or welds; equipment failure; incorrect operations; overpressurization of low-pressure distribution systems; and other threats that pose a risk to the integrity of a pipeline. An operator must also consider the age of the system, pipe, and components in identifying threats. An operator must consider reasonably available information to identify existing and potential threats. Sources of data may include, but are not limited to, incident and leak history, corrosion control records (including atmospheric corrosion records), continuing surveillance records, patrolling records, maintenance history, and excavation damage experience.

(c) *Evaluate and rank risk.*

(1) *General.* An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. 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. An 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, age, or environmental factors), and for which similar actions likely would be effective in reducing risk.

(2) *Certain pipe with known issues.* An operator must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], evaluate the risks in the distribution system resulting from pipelines with known issues based on the material (including, cast iron, bare steel, unprotected steel, wrought iron, and historic plastics with known issues), design, age, or past operating and maintenance history.

(3) *Low-pressure Distribution Systems.* An operator must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], 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. In the evaluation of risks, an operator must:

(i) Evaluate factors other than past observed abnormal operating conditions (as defined in § 192.803) in ranking risks, including any known industry threats, risks, or hazards to public safety that could occur on its system based on knowledge gained from available sources;

(ii) Evaluate potential consequences associated with low-probability events unless a determination, supported and documented by an engineering analysis, or an equivalent analysis incorporating operational knowledge, demonstrates that the event results in no potential consequences and therefore no potential risk. An operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with § 192.18 within 30 days of making such a determination. The notification must include the following:

(A) Date the determination was made;

(B) Description of the low-probability event being considered;

(C) Logic supporting the determination, including information

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from an engineering analysis, or an equivalent analysis incorporating operational knowledge;

(D) Description of any preventive and mitigative measures, including any measures considered but not taken;

(E) Details of the low-pressure system applicable to the event that results in no potential consequence and risk, including, at a minimum, the miles of pipe, number of customers, number of district regulators supplying the system, and other relevant information; and

(F) Written statement summarizing the documentation provided in the notification.

(iii) Evaluation of the configuration of primary and any secondary overpressure protection installed at district regulator stations (such as a relief valves, monitoring regulators, or automatic shutoff valves), the availability of gas pressure monitoring at or near overpressure protection equipment, and the likelihood of any single event (such as excavation damage, natural forces, equipment failure, or incorrect operations), that either immediately or over time, could result in an overpressurization of the low-pressure distribution system.

(d) *Identify and implement measures to address risks.*

(1) *General.* An operator must identify and implement measures to reduce the risks of failure of its distribution pipeline system. The measures identified and implemented must address, at a minimum, risks associated with the age of pipeline components, the overall age of the system and components, the presence of pipes with known issues, and overpressurization of low-pressure distribution systems. The measures must also include an effective leak management program (unless all leaks are repaired when found).

(2) *Minimization of Overpressurization of Low-Pressure Distribution Systems.* An operator must, no later than [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], implement the following preventive and mitigative measures to minimize the risk of overpressurization of a low-pressure distribution system that could be the result of any single event or failure:

(i) Identify, maintain, and obtain, if necessary, pressure control records in accordance with §§ 192.638 and 192.1007(a)(3).

(ii) Confirm and document that each district regulator station meets the requirements of § 192.195(c)(1) through (3). If an operator determines that a district regulator station does not meet the requirements of § 192.195(c)(1) through (3), then by [ONE YEAR AFTER THE PUBLICATION DATE OF THE RULE], the operator must take either of the following actions:

(A) Upgrade the district regulator station to meet the requirements of § 192.195(c)(1) through (3), or

(B) Identify alternative preventive and mitigative measures based on the unique characteristics of its system to minimize the risk of overpressurization of a low-pressure distribution system. The operator must notify PHMSA and State or local pipeline safety authorities, as applicable, no later than 90 days in advance of implementing any alternative measures. The notification must be made in accordance with § 192.18(c) and must include a description of 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.

* * * * *

§ 192.1015 [Removed]

■ 20. Remove § 192.1015.

PART 198—REGULATIONS FOR GRANTS TO AID STATE PIPELINE SAFETY PROGRAMS

■ 21. The authority citation for part 198 continues to read as follows:

Authority: 49 U.S.C. 60101 *et seq.;* 49 CFR 1.97.

■ 22. Amend § 198.3 by adding the definitions for ''Inspection person-day'' and ''State Inspection Calculation Tool (SICT)'' in alphabetical order to read as follows:

§ 198.3 Definitions.

* * * * *

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.

* * * * *

State Inspection Calculation Tool (SICT) means a tool used to determine the required number of annual inspection person-days for a State agency.

* * * * *

■ 23. Amend § 198.13 by revising paragraph (c)(6) to read as follows:

§ 198.13 Grant-allocation formula.

* * * * *

(c) * * *

(6) Number of state inspection person-days, as determined by the SICT and other factors;

* * * * *

Issued in Washington, DC, on August 23, 2023, under authority delegated in 49 CFR 1.97.

Alan K. Mayberry,

Associate Administrator for Pipeline Safety.

[FR Doc. 2023–18585 Filed 9–6–23; 8:45 am]

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March 18, 2025 Pipeline Investigation Report PIR-25-01

UGI Corporation Natural Gas-Fueled Explosion and Fire

West Reading, Pennsylvania
March 24, 2023

Abstract: This report discusses the March 24, 2023, natural gas–fueled explosion and fire at Building 2 of the R.M. Palmer Company, a candy manufacturer located in West Reading, Pennsylvania. The explosion destroyed the manufacturer's Building 2 and caused significant structural damage to its adjacent Building 1 and other surrounding structures. In total, 7 people were killed, 10 people were injured, and 3 families were displaced from a neighboring apartment building.

Safety issues identified in this report include degradation of a retired service tee, insufficient consideration of threats to pipeline integrity, the risk associated with unmarked private pipeline assets crossing public rights-of-way (for example, a public street), delayed evacuation of Building 2 despite detection of natural gas, natural gas safety messaging that may not reach certain members of the public, insufficient guidance on gas leak emergency procedures, absence of natural gas detection alarms in commercial buildings, and insufficient accessibility of gas distribution line valves.

As part of this investigation, the National Transportation Safety Board issued recommendations to the Pipeline and Hazardous Materials Safety Administration, the Occupational Safety and Health Administration, 50 states along with the Commonwealth of Puerto Rico and the District of Columbia, the Commonwealth of Pennsylvania, the Pennsylvania Public Utility Commission, the American Gas Association, the American Petroleum Institute, the Gas Piping Technology Committee, the Common Ground Alliance, the International Code Council, the National Fire Protection Association, UGI Corporation, and R.M. Palmer Company.

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Acronyms and Abbreviations

API	American Petroleum Institute
CEO	Palmer Chief Executive Officer
CFR	*Code of Federal Regulations*
CGA	Common Ground Alliance
DDRM	data-driven risk model
GOM	*Gas Operations Manual*
DIMP	distribution integrity management program
GIS	geographic information system
GPTC	Gas Piping Technology Committee
GPTC Guide	*Guide for Gas Transmission, Distribution, and Gathering Piping Systems*
ICC	International Code Council
IFC	International Fuel Code
IFGC	International Fuel Gas Code
IM	integrity management
Inside SLIP	inside service line inspection program
NFPA	National Fire Protection Association
NFPA 54	National Fuel Gas Code
NPRM	notice of proposed rulemaking
OSHA	Occupational Safety and Health Administration
PA One Call	Pennsylvania One Call System
PA PUC	Pennsylvania Public Utility Commission
PHMSA	Pipeline and Hazardous Materials Safety Administration
psig	pounds per square inch, gauge
PSMS	pipeline safety management system
RP	Recommended Practice
SME	subject-matter expert
VP	Palmer vice president of operations and technical services

Executive Summary

What Happened

On March 24, 2023, around 4:55 p.m., natural gas, which was transported through a UGI Corporation–owned pipeline, leaked into and accumulated in the basement of an R.M. Palmer Company candy factory building in West Reading, Pennsylvania. The gas ignited, causing an explosion and fire that killed 7 Palmer employees, injured 10 people, and destroyed the building. Another Palmer building, as well as an adjacent apartment building, were also severely damaged. Three families were displaced from the apartment building.

What We Found

In 2021, a UGI Corporation crew retired the Aldyl A polyethylene service tee, joining UGI's gas main to the service line for Palmer Building 2. The crew capped off the retired tee, which had been installed in 1982, and installed a new tee. The retired Aldyl A tee remained connected to the natural gas distribution system. We found that natural gas had migrated from the retired Aldyl A service tee through the ground then into the Palmer Building 2 basement, chocolate pipe conduits, and Building 1, and fueled the explosion in the Building 2 basement. We found that the 1982 retired service tee leaked because of degradation (slow crack growth of the Aldyl A tower shell and thermal decomposition of the Delrin insert) caused by exposure to elevated temperatures. Steam escaping through a crack in a corroded steam pipe nearby had significantly elevated the ground temperatures near the tee. We found that the omission from PA's One Call law of certain assets whose lines transport steam or other high temperature substances across public rights-of-way can pose a risk during nearby excavation. We further found that widespread adoption of best practices on 811 center membership can increase awareness of certain underground pipelines that cross public rights-of-way and prevent an accident like this one.

We found that, without sufficient threat information available for analysis in its distribution integrity management program (DIMP), UGI could not effectively evaluate and address the risk to pipeline integrity of plastic piping in elevated temperature environments and that by not addressing the threat posed by the steam pipe, UGI's DIMP was not effective in preventing the accident. We further found that operators may not be aware of where they may have plastic natural gas assets that are vulnerable to degradation in elevated temperature environments, so appropriate mitigations may not be in place. In this accident, we found that UGI lacked procedures and training for its field crews to report sources of elevated temperatures near their assets thus the threat posed by the steam pipe was not identified, and mitigative measures were not implemented. In addition, industry guidance highlighting the threat to pipeline integrity of exposure to elevated temperatures could improve awareness so that operators can effectively identify and manage the threat.

Although several employees reported smelling the gas in the buildings before the explosion, few evacuated. We found that had Palmer implemented natural gas emergency procedures and training before the accident, employees and managers could have responded by immediately evacuating and moving to a safe location. We further found that when businesses that use natural gas do not have natural gas emergency procedures and training, employees may be unaware or unsure of what to do if they smell natural gas. Further, we determined that natural gas alarms can alert people of a gas leak so they can evacuate the area; however, natural gas customers may not be aware of the necessity of such alarms. We also found that, because of their consensus-based nature and wide reach, model building or gas codes can be effective instruments to address natural gas–related risks to employees of businesses that use natural gas. Because adoption of these fuel gas codes and other rules related to natural gas alarms depends on state and local policies, widespread requirement of natural gas alarms will rely on action at the state and local level.

We found that natural gas pipeline operator public awareness programs may not reach certain members of the public who do not directly receive bill stuffers, making them potentially unaware of natural gas safety guidance. Further, because customers vary significantly in the number of occupants or residents, criteria for designating emergency valves that only count customers may not accurately reflect who could be affected by a natural gas outage or emergency or the severity of the effect. We also found that UGI did not effectively inspect and maintain its valves through its valve maintenance program, which led to a delay in shutting off gas to the affected area. Lastly, we found that the Pennsylvania Public Utility Commission refused to provide investigative information pursuant to the NTSB's federal authority.

We determined that the probable cause of the explosion was degradation of a retired 1982 Aldyl A polyethylene service tee with a Delrin polyacetal insert that allowed natural gas to leak and migrate underground into the R.M. Palmer Company candy factory buildings, where it was ignited by an unknown source. Contributing to the degradation of the service tee and insert were significantly elevated ground temperatures from steam escaping R.M. Palmer Company's corroded underground steam pipe, located near the service tee, that had been unmarked and cracked. Contributing to the steam pipe crack was soil movement and R.M. Palmer Company's lack of awareness of the pipe's corroded state. Contributing to the natural gas leak was UGI Corporation's lack of awareness of the nearby steam pipe, which led to an incomplete integrity management program evaluation that did not consider or manage the risk posed by the steam pipe. Contributing to the accident's severity was R.M. Palmer Company's insufficient emergency response procedures and training of its employees, who did not understand the hazard and did not evacuate the buildings before the explosion.

What We Recommended

We recommended that the Pipeline and Hazardous Materials Safety Administration (PHMSA) issue an advisory bulletin reviewing the details of this accident to natural gas distribution pipeline operators and advising them to address the risk associated with Aldyl A service tees with Delrin inserts by replacing or remediating them. We also recommended that PHMSA issue an advisory bulletin to operators referencing DIMP regulations and encouraging a one-time inventory of all plastic assets that are located in environments that experience or are at risk of elevated temperatures, identifying plastic assets in elevated temperature environments, and evaluating and mitigating risks to deter the degradation of these assets. In addition, we recommended that UGI inventory all its plastic natural gas assets that may be in elevated temperature environments and address the risk associated with these assets. We reiterated a 2021 recommendation to PHMSA to evaluate industry implementation of gas distribution pipeline integrity management requirements and develop updated guidance for improving the effectiveness of the requirements.

We further recommended that PHMSA find effective ways for operators to communicate with people who live, work, or congregate near natural gas distribution pipelines and help operators improve public awareness of natural gas safety. We then recommended that, based on these findings, the American Petroleum Institute update its public awareness standard to provide specific guidance to natural gas distribution pipeline operators on effective safety communications.

We recommended that the Occupational Safety and Health Administration require employers whose facilities use natural gas to implement natural gas emergency procedures and that Palmer revise its natural gas emergency procedure to direct all employees to immediately evacuate to a safe location when they smell natural gas. We also recommended that Pennsylvania modify its law on underground utility protection to require all owners and operators of pipelines transporting steam or other high-temperature materials located in public rights-of-way to register their assets with Pennsylvania One Call and that the Common Ground Alliance identify opportunities for improving adoption of its best practices on 811 center membership. To make sure operators consider consequences and emergency response times in determining the locations of critical valves, we recommended the Pennsylvania Public Utility Commission assess operators' methodology for this determination.

We recommended that the American Gas Association share the details of this accident with its members, encouraging them to evaluate the effectiveness of their public awareness programs and to promote the installation of natural gas alarms. We also recommended that the Gas Piping Technology Committee develop guidance to ensure natural gas pipeline operators' DIMPs appropriately assess and address threats to plastic pipelines from nearby temperature-elevating assets.

We recommended that 50 states, Puerto Rico, and the District of Columbia require the installation of natural gas alarms and that the International Code Council and the National Fire Protection Association revise codes to provide for natural gas emergency procedures and revise the fuel gas codes to provide for the required installation of natural gas alarms.

Finally, we recommended that the Commonwealth of Pennsylvania review and amend its statutes to facilitate sharing investigative information with the NTSB.

1 Factual Information

1.1 The Accident

On March 24, 2023, about 4:55 p.m. local time, a natural gas–fueled explosion and fire occurred at Building 2 of the R.M. Palmer Company candy factory in West Reading, a borough in Berks County, Pennsylvania. The explosion destroyed Building 2 and caused significant structural damage to the adjacent Building 1 and other surrounding structures, including an apartment building. (See figure 1.) In total, 7 people were killed, 10 people were injured, and 3 families were displaced from their apartments. The accident caused an estimated $42 million in property damage.[1] Weather conditions at the time of the accident were clear with no precipitation, the temperature was 52°F, and winds were about 5 mph from the southwest by south.

[1] Visit ntsb.gov to find additional information in the public docket for this NTSB accident investigation (case number PLD23LR002). Use the CAROL Query to search safety recommendations and investigations.

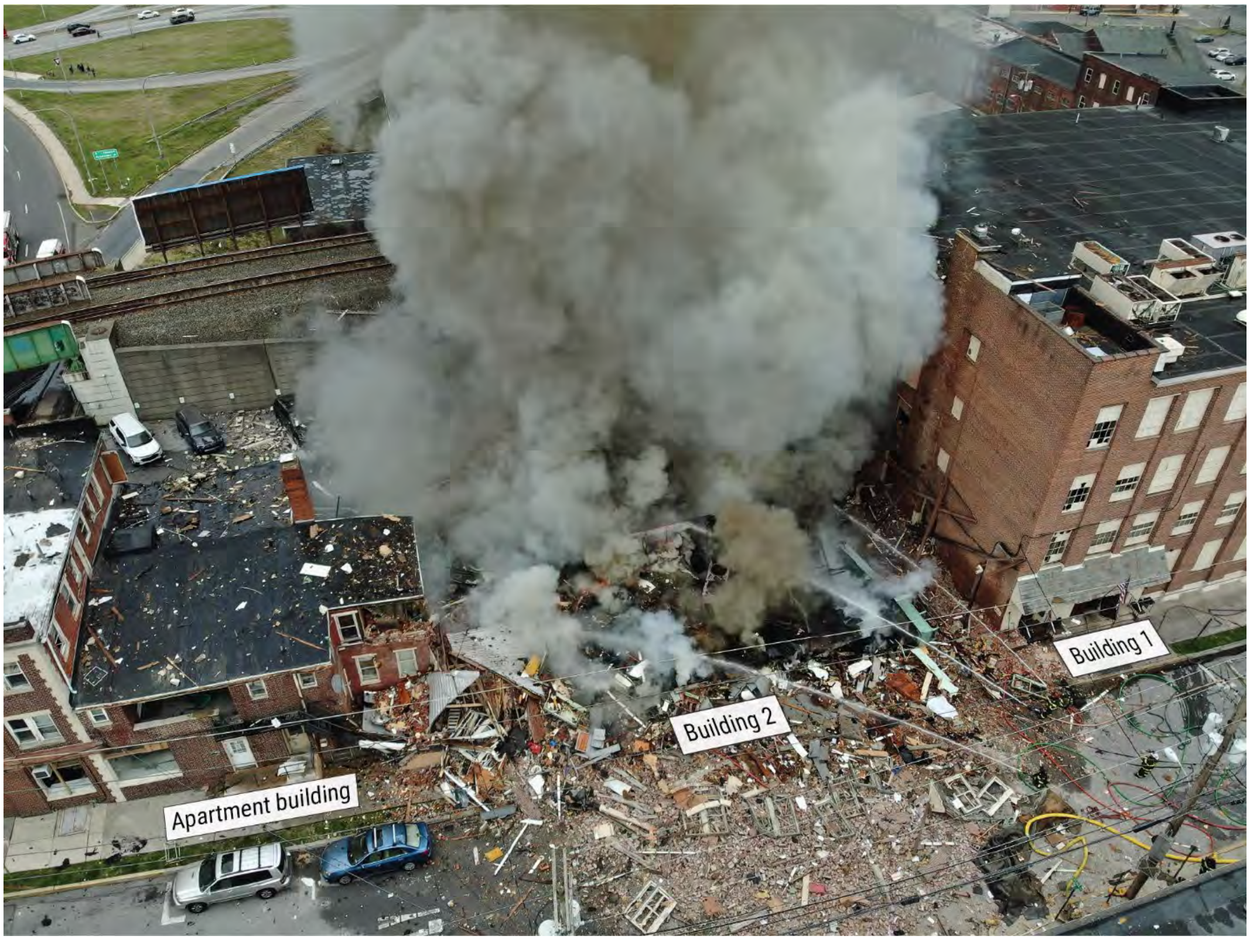

Figure 1. Overhead image of the accident. (Source: Western Berks Fire Department.)

1.1.1 Area Layout

Building 2, a two-story brick structure, was located at 17 South 2nd Avenue in West Reading. The four-story brick Building 1 was located at 77 South 2nd Avenue, south of Building 2. Cherry Street, a public right-of-way (alley), separated the two buildings. The affected apartment building, which comprised three households, was located 5 feet north of Building 2. (See figure 2.)

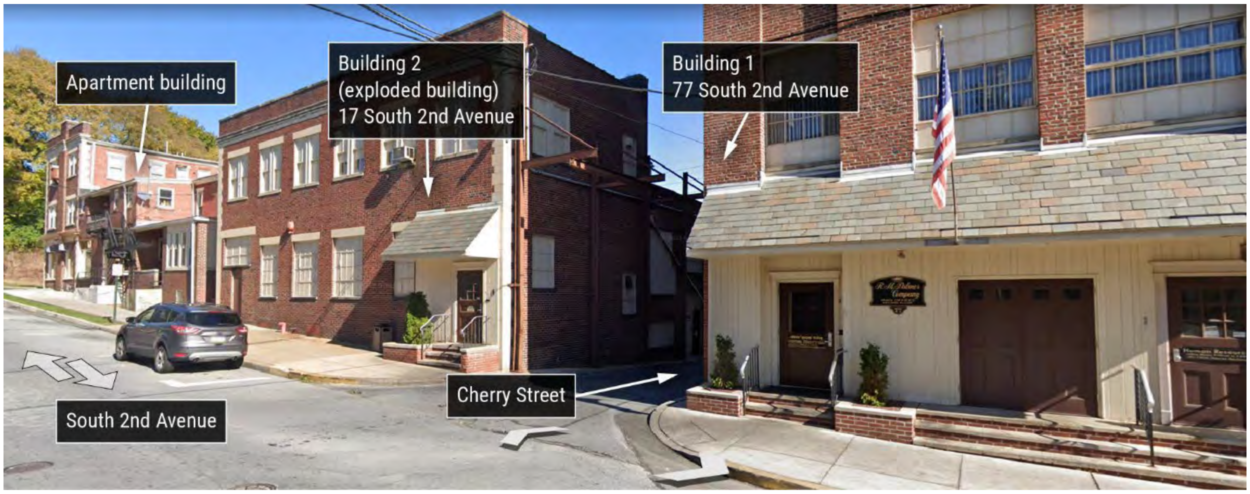

Figure 2. South 2nd Avenue before the accident. (Source: Google Photos.)

UGI Corporation owned and operated natural gas pipeline assets located within the public right-of-way near the accident site.[2] Natural gas was distributed to Palmer Buildings 1 and 2 from a UGI natural gas main that ran lengthwise underneath Cherry Street (Cherry Street main).[3] Near the intersection with South 2nd Avenue, the Cherry Street main transitioned from a short section of steel and then reduced to a 1.25-inch-diameter Aldyl A main, which was installed in 1982 (see section 1.5.1).[4] Aldyl A is the trademarked name of a polyethylene plastic gas pipeline product that was manufactured by the DuPont chemical company using a proprietary polymer resin. At the time of the accident, the Cherry Street main was operating about 53 pounds per square inch, gauge (psig). The maximum allowable operating pressure of the Cherry Street main was 60 psig. The main was about 3 feet below the road surface.

Palmer produces chocolate novelty candies for sale in the United States and internationally and has been in business in Pennsylvania since 1948. It has about 550 full-time employees and about 300 seasonal workers. Palmer's facilities at the time of the accident comprised six buildings, two in West Reading and four in Wyomissing,

[2] (a) See section 1.5 for UGI company information. (b) This report uses the term *asset* to refer to the specific elements of a pipeline distribution system.

[3] A *gas main* is a natural gas distribution pipeline that serves as a common source of supply for more than one service line. *Service lines* transport gas to a customer.

[4] In 1982, the Aldyl A gas main was installed by inserting it into a bare steel main from 1911. As was common practice at the time, once the Aldyl A main was inserted, the steel main was then abandoned. An *abandoned* pipeline is one permanently removed from service, no longer containing natural gas, as defined in Title 49 *Code of Federal Regulations* (*CFR*) 192.3.

Pennsylvania. In West Reading, Building 1 was used for candy production and as corporate headquarters, and Building 2 was used for candy production. Palmer-owned pipes (private pipes) ran underneath Cherry Street between Buildings 1 and 2: a steam pipe that delivered steam from the boiler to heat areas of Building 2, a condensate pipe that channeled condensation back to the boiler, and two conduits that together contained six supply pipes that delivered liquid chocolate from storage tanks in the basement of Building 2 to production areas in Building 1.[5] One conduit contained four chocolate supply pipes, and the other conduit contained two chocolate pipes. (See figure 3.) Electric heat tape affixed to the outside of the chocolate pipes kept the chocolate from solidifying in the pipes. The top of the steam pipe was about 1.5 feet below the road surface.[6]

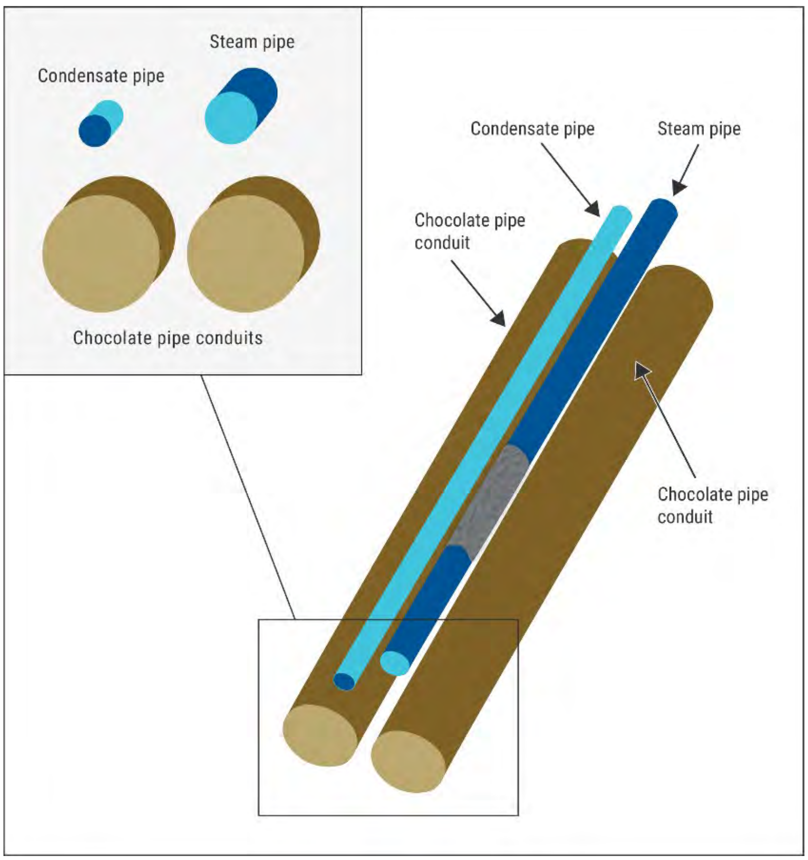

Figure 3. Arrangement of Palmer-owned pipes.

[5] These pipes were partially destroyed in the explosion and are no longer in use.

[6] Palmer began production in Building 2 in the mid-1960s. The National Transportation Safety Board (NTSB) interviewed a former Palmer employee who indicated the steam pipe had been installed before he began working there in the mid-1970s.

The Palmer-owned pipes laid above and perpendicular to the gas main, with steam flowing from Building 1 to Building 2. Palmer kept maintenance records of the steam heating system boiler unit. These records indicated that the unit was checked daily by Palmer mechanics and inspected annually by a contractor, but Palmer did not have any maintenance records for the steam pipe to Building 2.

1.1.2 Service Line and Tee Replacement at Palmer Building 2

Two years before this accident, on February 16, 2021, a UGI crew conducted a routine inspection of the Building 2 gas meter, which at the time was in the basement.[7] The crew detected gas inside the basement of Building 2 and at the service curb valve outside the building. UGI recorded this as a “grade C” leak, which required immediate attention or repair, and began a project to replace the service line and service tee from the Cherry Street gas main to Building 2 and to move the meter outdoors as required by UGI procedures. The service tee joined the service line to the main. The alignment of the private pipes and natural gas distribution system assets after the replacement project is shown in figure 4.

[7] This type of inspection, required by UGI’s *Gas Operations Manual* (GOM) and federal regulation to be conducted every 3 years on a medium-pressure system, is described further in section 1.5.2.

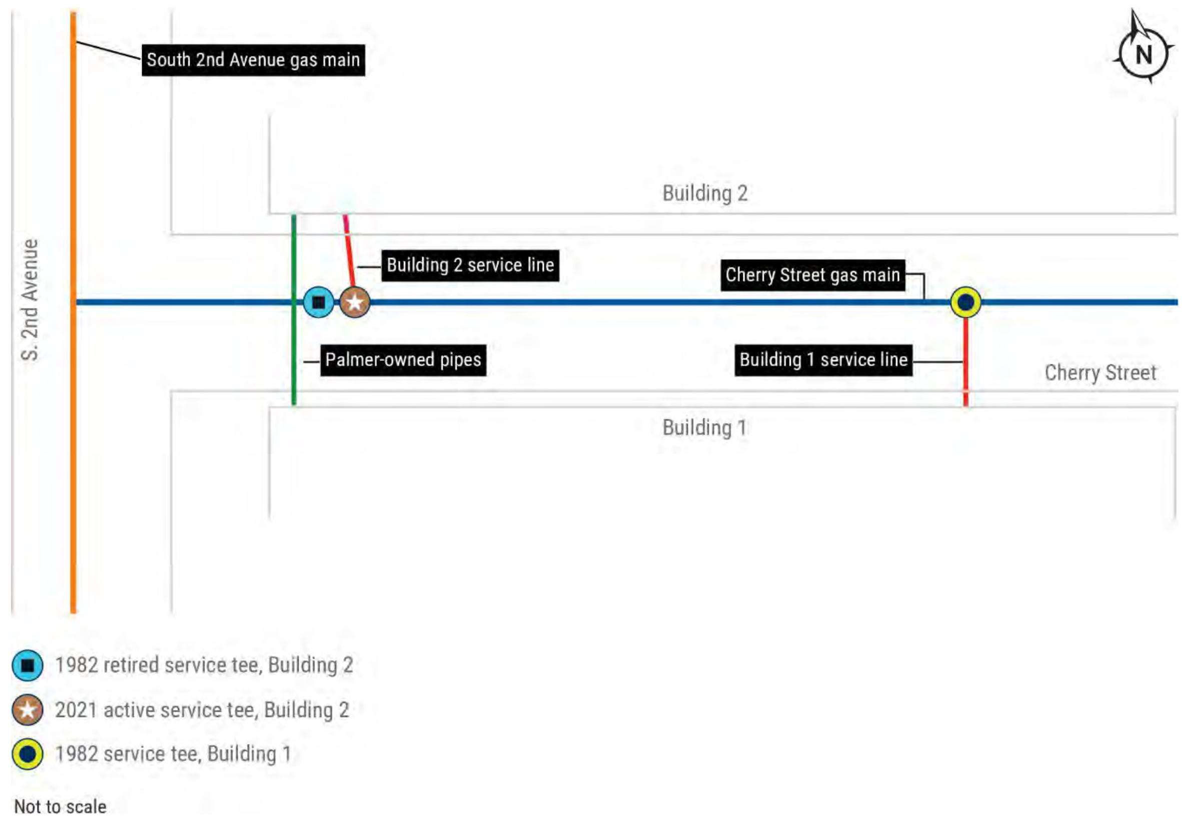

Figure 4. Natural gas distribution system and Palmer-owned pipes.

Before beginning excavation to replace the service line and move the gas meter, UGI submitted an emergency underground utility line locate request to the Pennsylvania One Call System (PA One Call) to mark existing utilities so UGI could repair a gas leak at Building 2.[8] Pennsylvania's Underground Utility Line Protection Law, Pennsylvania Act 287, as amended, requires owners or operators of underground lines that serve one or more customers or consumers in Pennsylvania to be a member of PA One Call, a privately funded nonprofit corporation that facilitates utility line location in all Pennsylvania counties.[9] PA One Call's interpretation of this law did not require Palmer to be a member, so its underground pipes were not included in the PA One Call database.

[8] Pennsylvania has recognized and adopted the uniform pavement marking colors outlined in the Common Ground Alliance's *Best Practices Guide* for underground piping or other utility assets.

[9] See Pennsylvania Statutes, Title 73 P.S. Section 176 et. Seq.

After the accident, the NTSB interviewed UGI crewmembers about the 2021 replacement of the Building 2 service line. A member of the UGI crew recalled seeing a subsurface white powder during excavation, located west of the service tee that they were replacing. The crewmember said that a Palmer employee came to the excavation site and indicated there was a steam pipe in the ground near or next to the white powder, the purpose of which was unknown. The UGI crewmember stated that he did not observe the steam pipe itself.

The crew did not attempt to expose the steam pipe to determine the actual location of the pipe or its distance from natural gas assets and did not notify UGI integrity management staff of a steam line in the vicinity of the assets. Palmer was not a PA One Call member, and was not required to be, so the locations of their underground pipes had not been marked.

The crew continued the excavation and completed the retirement of the original service line and tee and installation of the new service line and tee to the east of the old ones.[10] (See section 1.5.1 for a description of the typical process.) (See figure 5.) Upon completion of the project, the 1982 service line stub and tee remained attached to the gas main and exposed internally to full gas system pressure. UGI's standard and common industry practice for replacement of a service line and tee is to cap the tee and leave the tee attached to the main, exposed to full gas system pressure, and to install a new tee and service line nearby.

[10] This report uses the term *retired* to describe a natural gas asset that is no longer in use but that still contains natural gas. In this accident, the 1982 Aldyl A service tee to Building 2 was retired, therefore it is referred to in the report as the *retired service tee*.

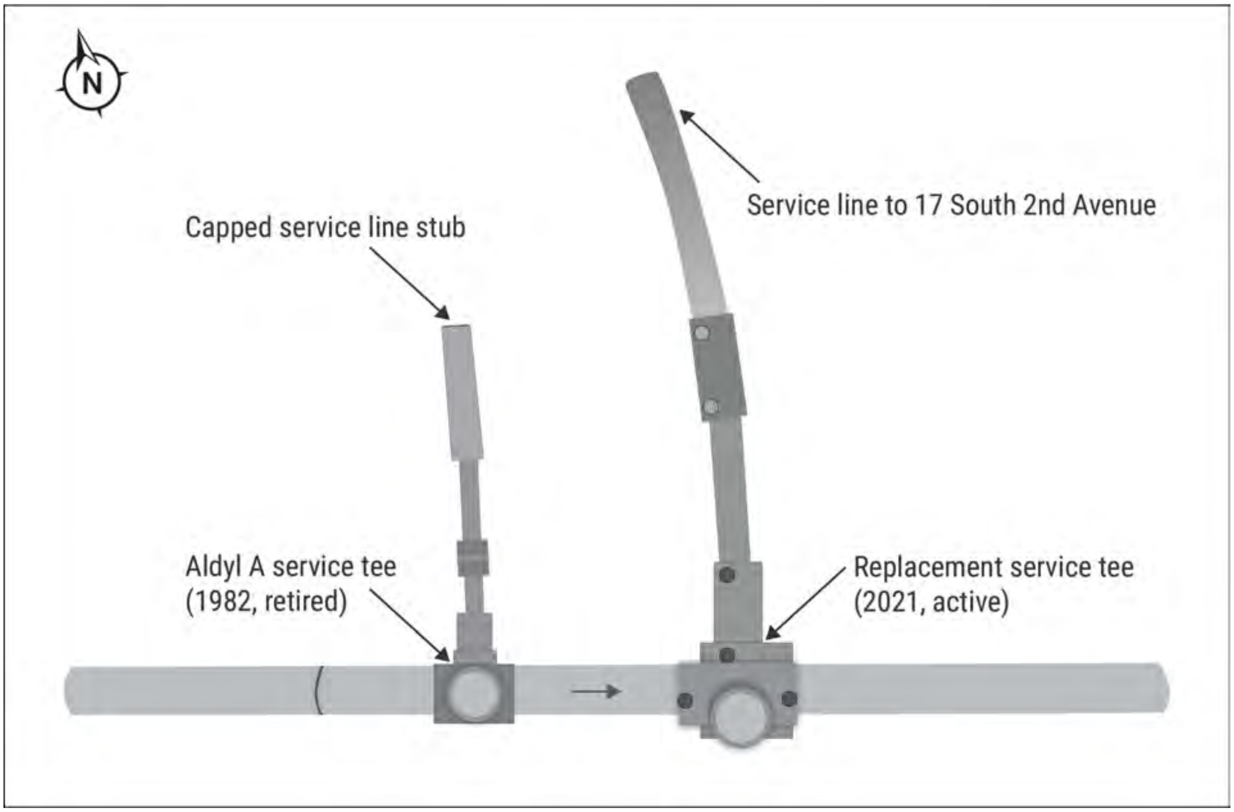

Figure 5. Cherry Street gas main and Building 2 service tees, viewed from above.

A review of PA One Call records indicated that no further work exposed the original service tee after February 16, 2021.

1.1.3 Natural Gas Leak and Explosion

On March 24, 2023, about 1.5 hours into the second shift at Palmer's West Reading facilities, employees in and around Buildings 1 and 2 began to smell natural gas odors, and some reported the smell to their supervisors.[11] Employees described

[11] Palmer production employees worked in shifts: the first shift was from 7:00 a.m. to 3:00 p.m., the second from 3:00 p.m. to 11:00 p.m., and the third from 11:00 p.m. to 7:00 a.m. In postaccident interviews with the NTSB, first-shift Palmer employees working in both Buildings 1 and 2 on March 24 did not recall a strange odor or one associated with natural gas.

this odor in various ways. Some identified it as a natural gas odor, others described it as a peculiar or strange odor.[12]

1.1.3.1 Building 1

About 65 employees, both production and office workers, were working in Building 1 at the time of the accident, with candy in production at that location. Several second-shift Palmer employees, working on the third and fourth floors in production areas that faced Cherry Street, told the NTSB they reported a gas odor to the second-shift supervisor between 4:20 and 4:46 p.m.[13] Some employees recalled that the second-shift supervisor told them they could go home early, but they told the NTSB they were concerned leaving would count against their workplace attendance.[14] In a postaccident interview with the NTSB, the second-shift supervisor stated she did not smell gas before the explosion. They did not leave the building before the explosion.

The Palmer receptionist, who worked in Building 1, told the NTSB that about 4:45 p.m., another employee who had already left for the day called from her car and notified the receptionist of a peculiar smell outside between Buildings 1 and 2, which the employee could not identify.

A custodian working the second shift in Building 1 told the NTSB that he smelled gas a little after 4:30 p.m. and reported it to the receptionist and his supervisor some time later.[15] He recalled asking his supervisor if she was going to leave the building on account of the natural gas odor. The supervisor responded that she was not going to leave, and she thanked him for letting her know about the odor. The custodian then self-evacuated from Building 1. Palmer management did not evacuate Building 1 before the explosion, and no employees pulled the fire alarm.

[12] Because natural gas is odorless, strong-smelling chemical additives called odorants are mixed with natural gas before distribution to help reduce the risk that leaks will go unidentified. The most common odorant added to natural gas is methanethiol, or methyl mercaptan, which has a characteristic “rotten egg” or sulfurous odor.

[13] These employees estimated the reporting times based on their second shift’s typical break time.

[14] According to interviews with Palmer employees, the company’s attendance policy penalized unreported or unexcused absences and leaving early from a shift.

[15] The Palmer receptionist did not confirm this report when interviewed by the NTSB.

1.1.3.2 Building 2

During the second shift, seven production employees were assigned to Building 2 in West Reading to clean and change over candy production equipment. The second shift employees who had worked in or entered Building 2 on the day of the accident told the NTSB that they did not smell gas at the beginning of their shift, about 3:00 p.m.

An assistant line technician working on the first floor of Building 2 told the NTSB that, about 4:30 p.m., he and his team leader, the lead line technician, heard the second-shift production employees working on the first floor of Building 2 complaining of a gas smell. The assistant line technician stated that he and the lead line technician went to the area of the complaint, where they too smelled a gas odor. He added that he self-evacuated from Building 2 soon after arriving there, because the smell of gas was strong enough to hurt his eyes, causing him physical pain.

An employee who packaged chocolates (packer) was one of the production employees working on the first floor of Building 2 who had complained of the gas smell. In an interview with the NTSB, the Building 2 packer recalled the lead mechanic entering Building 2 and saying he had smelled “a very strong gas smell” in that building and in Building 1. The packer stated that the lead mechanic then exited Building 2 to find out more about the gas odor. The lead line technician exited the building around the same time. The Building 2 packer and four other production employees remained inside; the packer stated that at the time of the accident, her understanding of employee protocol during such a situation was that they must stay at their workstations and await instructions from a supervisor. She told the NTSB she had worked at Palmer for 4 years.

The NTSB reviewed surveillance camera data of Buildings 1 and 2 just before the explosion. Table 1 shows times and employee movements.

Table 1. Surveillance camera data from in and around Buildings 1 and 2 before the explosion.

Time[1]	Location	Description
4:42 p.m.	Building 1	Palmer receptionist received call from an off-duty employee who reported a strong odor outside the buildings
4:42 p.m.	Building 2	Lead mechanic entered Building 2
4:43 p.m.	Building 2	Assistant line technician exited Building 2
4:44 p.m.	Building 2	Lead mechanic exited Building 2 and met with lead line technician
4:47 p.m.	Cherry Street	Lead mechanic and lead line technician looked at the gas meter, which was attached to the southwest wall of Building 2 facing Cherry Street
4:49 p.m.	Building 1	Custodian had discussion with receptionist, motioning to his head and face
4:52 p.m.	Cherry Street	Truck driver looked at gas meter with lead mechanic
4:53 p.m.	Cherry Street	Plant manager and lead mechanic looked at gas meter and sidewalk below it
4:54 p.m.	Building 2	Plant manager and lead mechanic entered Building 2 through basement door on Cherry Street
4:54 p.m.	Cherry Street	Human resources director looked at gas meter and sidewalk below it
4:55 p.m.	Building 2	Human resources director appeared to be smelling the area as she entered Building 2 through front door; lead line technician held door for her
4:55 p.m.	**Building 2**	**Explosion**

A truck driver who was on Cherry Street delivering liquid chocolate by hose into Building 1 told the NTSB that, while working around his truck, he smelled an unfamiliar odor. He discussed it with the Palmer lead mechanic, who was standing outside Building 2 with the Palmer plant manager; the truck driver recalled the lead mechanic suggesting the odor could be "raw sewage" or "methane."[16] The truck driver told the NTSB that the lead mechanic and plant manager entered the

[16] Methane is the primary component of natural gas.

basement of Building 2 just before the explosion. Palmer management did not evacuate Building 2 before the explosion, and no employees pulled the fire alarm.

1.2 Injuries and Damages from the Explosion and Gas Fire

The explosion killed seven Palmer employees.[17] Six died from blast injuries and one from extensive thermal burns. All were in Building 2 at the time of the explosion.

Three Palmer employees and the truck driver sustained serious injuries in the blast and subsequent fire. One of these three Palmer employees, the Building 2 packer, was inside Building 2 at the time of the explosion. The other Palmer employees who sustained serious injuries, the lead line technician and assistant line technician, were positioned near Building 2's front entrance, and the truck driver was on Cherry Street. Three Palmer employees near the buildings received minor injuries. Three bystanders, who assisted the injured after the explosion, also received minor injuries. The explosion destroyed Building 2 and severely damaged Building 1.

1.3 Emergency Response

A total of 30 fire and rescue companies, 15 law enforcement agencies, 9 emergency medical services, and 2 local urban search and rescue companies responded to the accident. The Pennsylvania Emergency Management Agency sent a supporting task force.[18] Before the NTSB launched an official investigation on March 28, various federal and state agencies, along with UGI, also responded.[19]

[17] The Palmer plant manager, human resources director, and lead mechanic, as well as four of the production employees working on the first floor of Building 2, were killed in the explosion.

[18] Pennsylvania Task Force 1, which is coordinated through the Philadelphia Fire Department, is one of 28 Federal Emergency Management Agency Urban Search & Rescue response teams.

[19] (a) Federal and state agencies included the Pipeline and Hazardous Materials Safety Administration (PHMSA), the US Chemical Safety and Hazard Investigation Board; the Occupational Safety and Health Administration (OSHA); the Bureau of Alcohol, Tobacco, Firearms and Explosives; and the Pennsylvania Public Utility Commission (PA PUC). (b) The NTSB sent an investigator on March 25, 2023, to monitor the accident in person. Once the NTSB determined it had jurisdiction over the investigation according to 49 U.S.C. 1131(a)(1)(D), it officially launched investigators on March 28. The NTSB has jurisdiction over certain natural gas pipeline accidents occurring while natural gas is in transportation, rather than those originating from customer-owned piping or appliances within a building.

1.3.1 R.M. Palmer Emergency Response

A Palmer packer who had been working the second shift on the third floor in Building 1 told the NTSB that, when the explosion occurred, the north wall of Building 1 seemed to explode and cause the floor to crack. After the explosion, she recalled that people began to run and that many people were screaming. Alarms went off throughout Building 1, and the Building 1 packer ran with other employees toward the building exits. A mechanic, also working in Building 1, stated that the building shook from the explosion, causing many employees to fall to the ground. The mechanic added that he shouted for people to get out of the building as he and other employees ran toward the exits. All staff who had been working in Building 1 exited to the parking lot, where an employee conducted a headcount. Building 2 was destroyed.

1.3.2 Local Emergency Response

Around 4:56 p.m., personnel from the City of Reading Fire Department, a half mile away from the Palmer buildings, heard the explosion and self-dispatched to the accident scene to suppress the fire and search for victims in the building rubble. The Berks County Department of Emergency Services received the first 9-1-1 call about the explosion at 4:57 p.m. The West Reading, Wyomissing, and Spring Township Fire Departments also arrived to assist with extricating victims. In a postaccident interview with the NTSB, a City of Reading Fire Department deputy chief recalled seeing heavy fire coming from the rubble of Building 2, with flames more than 40 feet high extending through the pile of debris.

Around 5:00 p.m., the City of Reading Fire Department requested that UGI respond to the incident. About 13 minutes later, the City of Reading fire chief reported fire under the sidewalk pavement near Building 2. Incident command was transferred around 5:21 p.m. from the City of Reading to the West Reading fire chief, who later told the NTSB he smelled gas and observed flash fires over the firefighters as they moved through the rubble.[20] Firefighters from the West Reading Fire Department searched Building 1 after hearing reports of a possible gas leak. They reported a gas-fed fire in the basement of Building 1, coming from an underground

[20] Three incident commanders worked alongside one another as a unified command to manage different response operations. The West Reading Fire Chief took command of the fire and rescue scene. The West Reading Police Chief secured the area, accounted for employees, and blocked traffic. Personnel from Western Berks Ambulance handled incident command for the emergency medical services.

conduit (carrying the chocolate pipes) that ran beneath Cherry Street between Buildings 1 and 2.

The West Reading fire chief recalled that after the explosion, UGI had reported problems closing underground gas main valves to isolate the gas system or stop the flow of gas feeding the fire (see section 1.3.3 for further details).[21] After the natural gas system was isolated around 6:15 p.m., the main fire went out, and firefighters extinguished the remaining pockets of fire. Emergency response personnel also rescued five people from the apartments next to Palmer Building 2.

Search and rescue operations continued for 3 days through March 27, 2023, when the last accident victims were found.

1.3.3 UGI Emergency Response

After the explosion, UGI worked to isolate the gas system in the area of the accident. The first UGI employee to respond to the accident was a mechanic who had been working nearby. In an interview with the NTSB, he recalled that UGI dispatch called to notify him of the explosion and that he arrived at the incident location around 5:19 p.m. He received valve identification numbers over the phone and was directed to shut off two underground gas main valves near the exploded building.

The UGI mechanic closed the first valve, at South 2nd Avenue and Franklin Street, about 5:30 p.m. (Figure 6 shows the locations of the valves UGI closed or attempted to close in response to the accident.) He recalled that when he went to the second valve at South 2nd Avenue and Penn Avenue, the valve identification number that he had received did not match the valve itself. A UGI representative later stated that the South 2nd Avenue and Penn Avenue valve was inaccessible and paved over and that consequently this valve was not closed during the response. [22] The UGI representative stated later that personnel tried to verify the gas valve's identification numbers and were unable to do so. At the time, they were not viewing the paved-over gas valve but instead a water valve that, for an undetermined reason, had a gas valve cover. UGI had designated this valve, and all the other valves it closed or

[21] *Valves* are closed to isolate a pipeline segment.

[22] It is not typical practice for a gas valve to be paved over.

attempted to close during its response to the accident, as secondary valves.[23] More information on inspections of these valves can be found in section 1.5.3.

UGI added that upon encountering this issue, the UGI mechanic used geographic information system (GIS)–based maps and records to identify the next-closest valve needed to isolate the main segment; this valve was located at South 3rd Avenue and Penn Avenue. The UGI mechanic subsequently closed the South 3rd Avenue and Penn Avenue valve about 5:50 p.m., shutting off gas flowing north to south. He then moved to the final valve at South 4th Avenue and Penn Avenue that, when closed, shut off gas flowing west to east and completed the isolation of the gas system in the affected area.

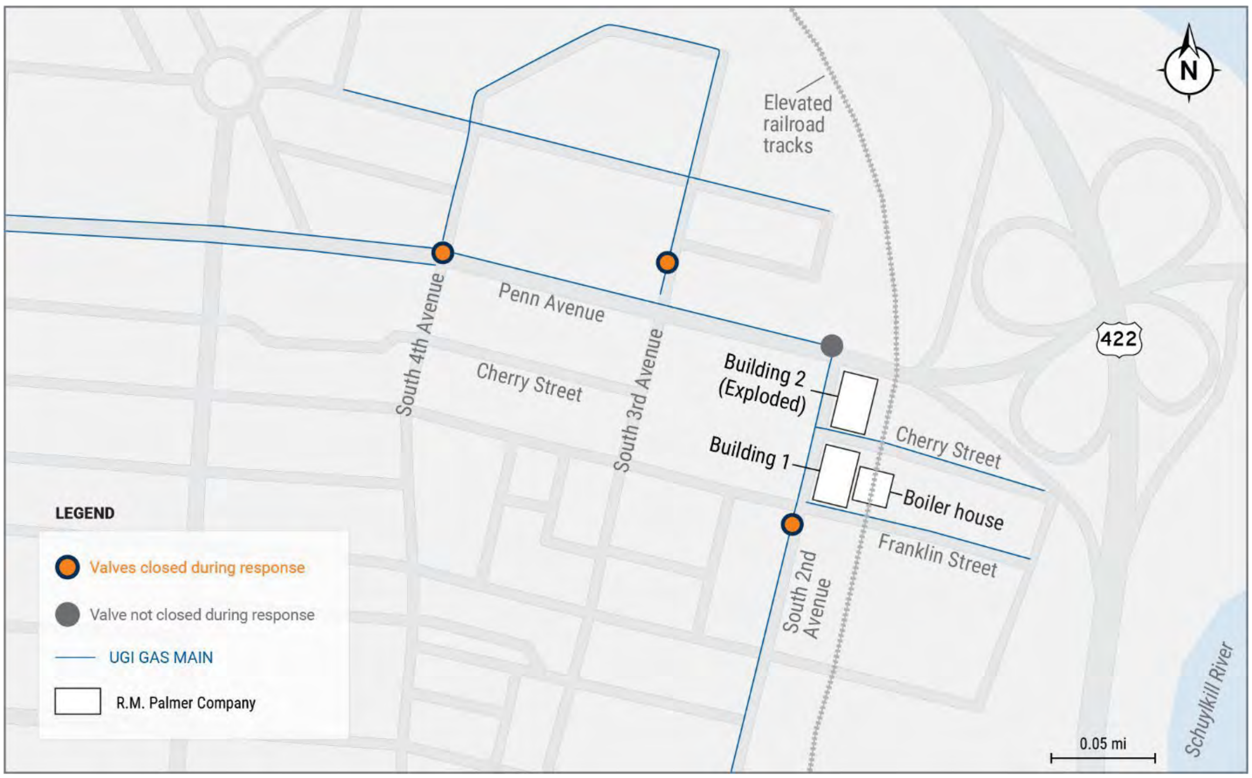

Figure 6. Underground gas main valves involved in response to the March 24 incident.

[23] (a) UGI referred to the valves necessary for the safe operation of a distribution system, as specified by 49 *CFR* 192.747, as *critical valves* and those not necessary for the safe operation of a distribution system as *secondary valves*. (b) UGI's secondary valves were subject to design requirements in 49 *CFR* 192.181, "Distribution line valves." For more on the regulatory application of these requirements, see https://www.phmsa.dot.gov/regulations/title49/section/192747 and https://www.phmsa.dot.gov/regulations/title49/section/192181.

UGI emergency responders told the NTSB that they were not able to close the final valve at South 4th Avenue and Penn Avenue until about 6:15 p.m. because of dirt and debris inside the valve box. Once a vacuum truck arrived and removed the debris, the UGI emergency responders closed the valve, isolating the gas system in the area of the explosion about 1 hour after the responders first arrived on the scene.

1.4 R.M. Palmer Facilities and Heating System

At Palmer's West Reading facilities, candy operations involved molding, decorating, and foiling chocolate in four production areas located in Buildings 1 and 2.[24] Liquid chocolate was delivered at least daily by truck from an outside supplier and transferred by hose and piping into storage tanks in the basements of Buildings 1 and 2, which ranged in capacity from 4,000 to 7,700 gallons. The chocolate was kept liquid in the tanks by an ambient room temperature of 105–110˚F, which was maintained by ceiling-mounted natural gas–fueled heaters. The liquid chocolate was then pumped from the tanks through the chocolate supply pipes to the various production areas within Buildings 1 and 2. Aside from the Building 2 basement heaters, other natural gas–fueled appliances at the accident location included a water heater in the Building 2 basement, a natural gas–fueled steam boiler located to the east of Building 1 for heating both buildings, and a gas-fueled generator outside Building 1 used as a backup energy source for the computer system.

Palmer's heating system was active at the time of the accident and had been for the previous several months. According to Palmer, steam flowed periodically from the boiler, which operated at 15 psig, based on heat demand in Building 2. The steam flowed to a regulator valve in Building 1 that dropped the pressure to 9 psig, and from there through a pipe underneath Cherry Street to Building 2.[25] Condensation from the steam heating system collected in a tank in the Building 2 basement and was pumped periodically back through the condensate pipe to the boiler.

In an interview with the NTSB, the truck driver who was making a delivery at the time of the accident stated he could recall the construction on the day of the 2021 UGI service tee replacement, because he had waited for the UGI crew to finish their work before completing his delivery. The truck driver stated that after that day, when

[24] *Foiling* involved adding foil wrappings to the molded candies.

[25] At 9 psig, the temperature of saturated steam is 237°F.

it was cold out, he would see steam rising from the section of asphalt covering the service tee replacement, and only that section.

1.5 UGI Corporation

UGI Corporation's subsidiary UGI Utilities Inc. serves about 688,000 natural gas customers and 63,000 electric customers in Pennsylvania and Maryland. UGI's annual throughput is about 314 billion cubic feet of natural gas and 1 billion kilowatt-hours of electricity. UGI's natural gas assets near the accident site are described in section 1.1.

1.5.1 Cherry Street Gas Main and Service Information

The Cherry Street Aldyl A gas main was installed in 1982. Service tees were used to branch off the main to provide gas service to Buildings 1 and 2. The tees were composed mostly of Aldyl A polyethylene components. Such tees had inserts and caps made of polyoxymethylene homopolymer, also known as polyacetal or Delrin.[26] The NTSB reviewed the specifications for Aldyl A service tees with Delrin inserts. The specifications indicate a maximum ground temperature of 100°F.

These tees were designed to perform three functions: (1) form a leak-free connection with the gas main, (2) form a leak-free connection to downstream service line piping, and (3) perforate the gas main to allow gas to enter the service line. The first function was accomplished by saddle fusing the tee to the gas main.[27] To complete the second function, service line piping and fittings were attached to the tee's outlet. Once a leak-free connection was established, the third function was accomplished using a cutter that was housed in the tower of the service tee. To complete this function, the cutter was lowered using a wrench until its tip cut a circular hole in the top of the gas main. The cutter was next raised to clear the cut hole and allow gas to enter the service line. The tee was then sealed by installing a threaded cap with rubber O-ring on top of the tee's tower. (See figure 7.)

[26] For more on the NTSB Materials Laboratory examination of the Building 2 service tee, see section 1.6.2.1.

[27] *Saddle fusing* joins a *saddle*—a fitting that holds a tee onto a pipe—to the pipe by heating the external surface of the pipe and the matching surface of the fitting.

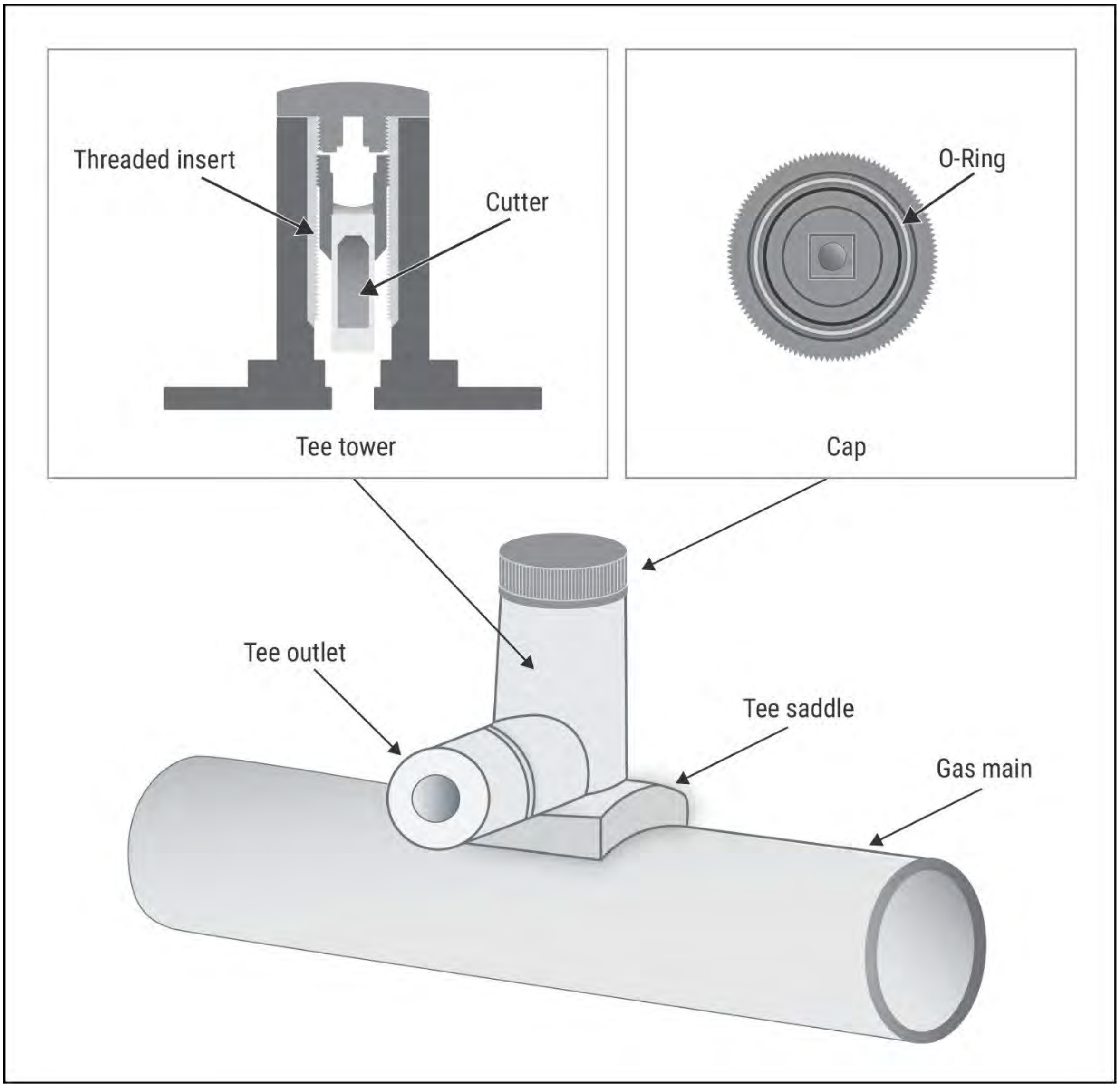

Figure 7. Aldyl A service tee and its components.

After the accident, the NTSB interviewed the crewmembers who had installed the new service tee and line to Building 2. None could recall the exact process of the 2021 service line and tee replacement, but they outlined the typical process. This included shutting off the gas flow at the old service tee by lowering the tee's internal tap to stop the flow of gas into the service line, cutting off the service line, and capping the remaining service line stub.[28] The internal tap in the service tee was then

[28] (a) This type of tee is also known as a tapping tee. (b) A *service line stub* is a short section of capped-off pipe that remains attached to a retired tee, as the tap itself is not designed to stop all the gas flow into the service line when it is lowered in the tee.

raised to reintroduce gas flow to the service line stub, and a soap test was conducted to verify the repair was leak free.[29]

1.5.2 UGI Leak Surveys Since 2011

UGI performed leak surveys (inspections to identify leaks) on (or over) the Cherry Street main in July 2011, July 2015, and June 2019, and on the service line to Building 2 in November 2014, August 2017, and August 2020.[30] No leaks were found during any of these surveys.

UGI also conducted three indoor leak surveys, two as part of its inside service line inspection program (Inside SLIP) and one when replacing some meters.[31] A 2018 Inside SLIP survey and a 2020 meter replacement found no leaks. The Inside SLIP survey on February 16, 2021, found a leak inside the Building 2 basement and just outside the building, and the meter was moved and the service line and tee replaced. (see section 1.1.2.)

1.5.3 Valve Inspections

UGI's GOM included procedures for valve maintenance and guidelines for maintaining and inspecting critical valves (also referred to in the industry as operating or emergency valves) and secondary valves. The procedures required that critical valves be inspected annually, that secondary valves be inspected at least once every 5 years, and that, during inspections, valves must be operated to determine whether they would work in an emergency. According to records from UGI and the Pennsylvania Public Utility Commission (PA PUC), the four valves that UGI personnel tried to close to isolate the system following the March 24, 2023, explosion were secondary valves and had been inspected on a regular, 5-year schedule as set by

[29] In a *soap test*, a soapy mixture is applied to piping surfaces to check for air or gas leaks. Bubbles will form at the site of a leak. Procedures for the retirement of service lines in the GOM include a soap test once the work is complete.

[30] Leak survey types and frequencies are specified in the GOM. Survey schedules vary based on pipeline materials and location. The regulatory schedule specified by 49 *CFR* 192.723 for leak surveys in business districts is once a year at intervals no longer than 15 months and outside business districts at least once every 5 calendar years at intervals no longer than 63 months. UGI did not consider the accident location to be a business district.

[31] Inside SLIP surveys were required by the GOM to be conducted every 3 years.

UGI.[32] UGI's reports of the most recent inspections of the four valves UGI attempted to operate in response to this accident are shown in table 2.

Table 2. Reported valve inspections.

Valve Locaton	Date (Time Before the Accident)	Reported Result
South 2nd Avenue/Penn Avenue	March 23, 2021 (24 months)	Cleaned valve box or pit
South 3rd Avenue/Penn Avenue	April 16, 2020 (35 months)	Turned/key on
South 4th Avenue/Penn Avenue	March 2, 2022 (12 months)	Turned/key on, cleaned valve box or pit
South 2nd Avenue/ Franklin Street	March 2, 2022 (12 months)	Turned/key on

The gas valve at South 2nd Avenue and Penn Avenue was not positively identified by UGI's mechanic during the emergency response; he was unable to verify the gas valve's identification number to confirm that it was the valve he intended to shut off. In July 2024, at the NTSB's request, UGI excavated the site and found the gas valve under a layer of asphalt near two water valves (water valves A and B).

A 2018 photograph provided by UGI of South 2nd Avenue and Penn Avenue is shown in figure 8 along with an inset image of the uncovered gas valve and water valve A from UGI's 2024 excavation. The gas valve is not visible in the 2018 image. A UGI representative stated that during the 2021 inspection, UGI personnel likely located a nearby water valve that had a gas cover (water valve A) and that they had likely inspected that valve.[33] He further stated that the appearance of and the mechanism used to operate the types of water and gas valves found at that location were nearly identical.

[32] Although PHMSA is primarily responsible for developing, issuing, and enforcing safety regulations for pipelines, states assume intrastate regulatory, inspection, and enforcement responsibilities under an annual certification with PHMSA. UGI is regulated by the PA PUC, which adopts the federal standards as their own. See *Pennsylvania Code*, Title 52, Chapter 59, "Gas Service."

[33] Valve identification numbers are typically located on plastic tags affixed to valve lids.

Figure 8. South 2nd Avenue and Penn Avenue intersection in 2018 (*main image*) and during an excavation in 2024 (*inset*); water valve A had a gas cover. (Source: Google Street view via UGI.)

The NTSB reviewed UGI's criteria for designating what it called critical valves. Under the criteria, UGI installs critical valves based on blocks containing a maximum of 1,000 customers that would be affected in an outage or emergency. The customer count does not distinguish between schools, businesses, or individual residences. Secondary valves are installed for operational convenience or to facilitate construction. If these valves are readily accessible, they may be used in an emergency.

1.6 Postaccident Examinations and Testing

After the accident, several responding organizations evaluated the site and the affected gas distribution system, and the NTSB launched an investigation on March 28, 2023. Between March 28 and April 27, the NTSB conducted a series of examinations and tests to determine the source of the natural gas that had fueled the explosion. The following section presents the results of responding organizations' evaluations before March 28 and of examinations and tests conducted or overseen by the NTSB after its investigation began.

1.6.1 On-Scene Examinations

1.6.1.1 Explosion and Fire Origin Investigation

A federal, state, and local law enforcement team investigated the origin and cause of the Building 2 explosion and fire.[34] According to their report, the origin of the explosion and fire was the southwest quadrant of the Building 2 basement. The report describes three burn patterns, all in the southwest corner of the basement: one where the chocolate pipe conduits entered the basement; one to the right of the conduits, where a long-unused gas pipe (not pressurized with gas) entered the basement; and one around cracks and voids in the basement wall. The basement contained many pieces of mechanical and electrical equipment that could have provided an ignition source. The precise ignition source could not be determined, and the incident was classified as accidental.

1.6.1.2 UGI Odorant Checks and Leak Survey

After the accident on March 24, UGI performed odorant checks and found that odorant was readily detectable.[35] UGI performed leak surveys and initial bar hole testing daily starting on March 24 along the closest gas mains serving the Palmer buildings that were accessible at the time, on the sidewalk along South 2nd Avenue between Franklin Street and Penn Avenue.[36] No gas was detected.

The day after the accident, on March 25, the PA PUC oversaw a UGI contractor performing a leak survey on Cherry Street adjacent to Building 2 using remote methane leak detector equipment. The leak source could not be identified by these tests. The PA PUC further oversaw gas quality sampling and bar hole testing that,

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[34] The team included the Bureau of Alcohol, Tobacco, Firearms and Explosives; the Pennsylvania State Police; the West Reading Police Department; and the local fire marshal.

[35] UGI used odorant detection equipment to test the odorant concentration at five locations on the natural gas distribution system, including two near the Palmer buildings.

[36] *Bar hole testing* describes a gas measurement technique in which a small diameter hole is made in the ground, a bar hole probe is inserted into the hole, and a gas measurement is made. This technique identifies the extent of the natural gas in the ground in all directions from the depth of the pipeline upward.

along with similar testing from UGI, indicated the natural gas likely came from UGI's system rather than from a source of naturally occurring methane.[37]

1.6.1.3 Gas Migration Study and Bar Hole Tests

On March 30, the NTSB directed and oversaw a gas migration study, beginning with 14 planned bar hole readings and extending to 43 readings in a 3-by-3-foot grid on South 2nd Avenue at the Cherry Street intersection.[38] Gas was detected adjacent to Building 2 at the intersection of Cherry and South 2nd Avenue. Readings ranged from 0% to 17% gas in air by volume. The flammable or explosive range of natural gas is between 5% and 15% gas in air by volume.

On April 22, 2023, when Building 1 had been stabilized and the area between Buildings 1 and 2 became safe for people to access, the NTSB conducted another gas migration study using bar hole testing on Cherry Street. The NTSB detected gas between the main and curb lines adjacent to Building 2. Readings ranged from 0% to 0.80% gas in air by volume. The results of the March and April bar hole tests are shown in figure 9.

[37] Echelon Applied Geochemistry, which conducted the testing for the PA PUC, analyzed gas geochemistry and soil gas concentration data. The NTSB was present during this test.

[38] A *gas migration study* is an analysis of bar hole testing results to assess the extent in all directions of natural gas migration in the ground.

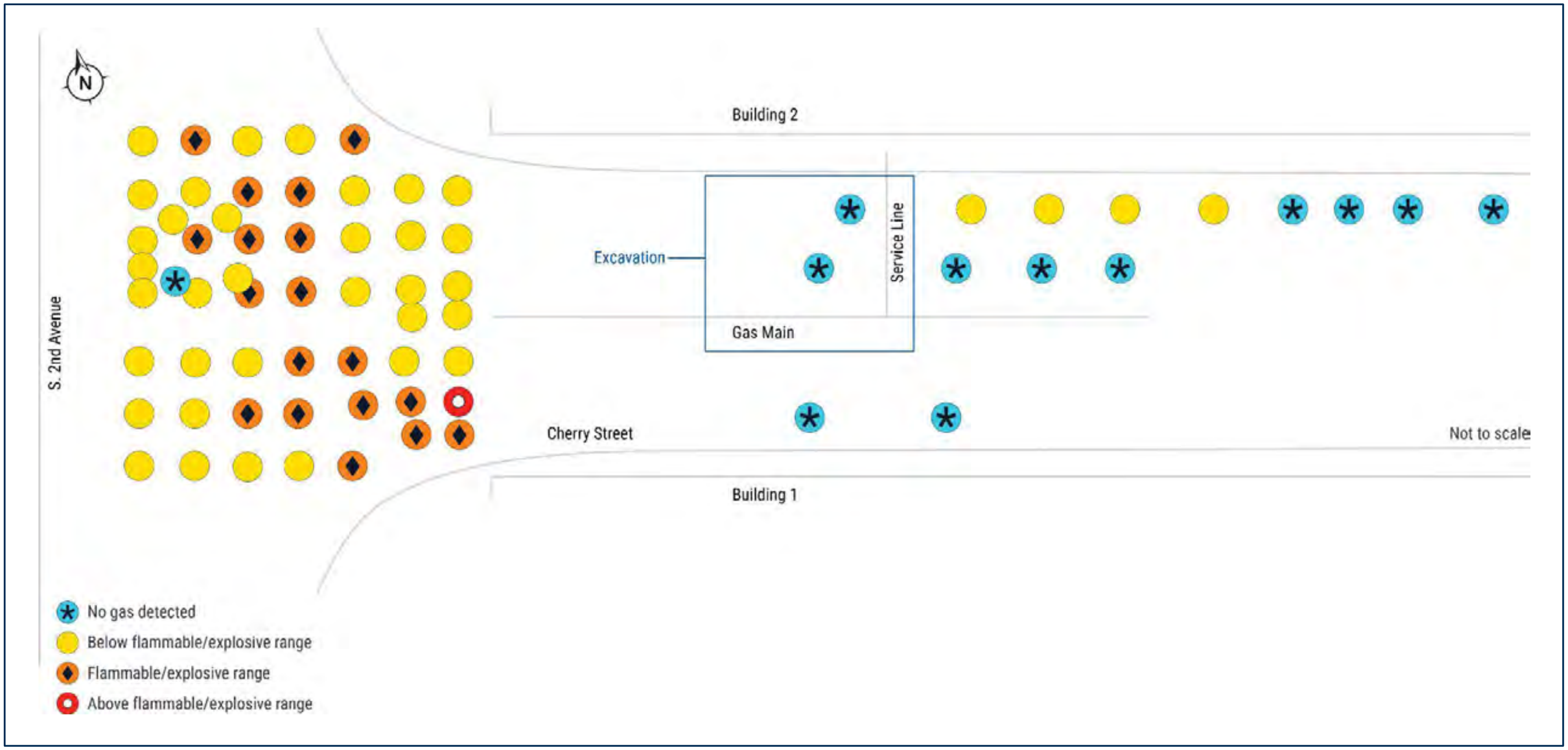

Figure 9. Bar hole test readings conducted in March 2023 (*left side of image*) and April 2023 (*right side of image*).

1.6.1.4 Flow Rate Test and Airflow Observations

On April 23, the NTSB directed and oversaw a flow rate test, in which UGI personnel pressurized the Cherry Street main with compressed air to quantify the leak rate of the gas that had been detected near Building 2 during the March and April gas migration studies.[39] Flow test results indicated that a leak rate of about 115 cubic feet per minute (natural gas equivalent) was present in the Cherry Street main when it was pressurized to about 39 psig.[40]

During the flow rate test, investigators went to the Building 1 basement and viewed the two underground chocolate pipe conduits that connected Buildings 1 and 2 to find possible pathways for gas migration. This was the same area where firefighters observed a fire during their initial response to the accident (see section 1.3.2). The NTSB observed air flow entering the basement through the conduits. When the flow rate test was terminated, investigators no longer detected air flow through the conduits.

1.6.1.5 Pressure Tests

UGI crews evaluated the integrity of the natural gas assets near the accident site as they became safe to access. First, a pressure test was conducted on the South 2nd Avenue main on March 29. The tested section held pressure for the length of the test, 1.5 hours. Next, on April 2, an accessible portion of the Cherry Street main was also pressure tested and held pressure for 1.5 hours.[41] The service line to the boiler house behind Building 1 was tested and held pressure for 1.5 hours.

On April 22, after the bar hole testing confirmed natural gas concentrations in the ground, the NTSB oversaw an initial pressure test of the portion of Cherry Street main between Buildings 1 and 2. The gas main failed to hold pressure. NTSB investigators smelled gas near the service riser to Building 2 and from an excavated area on South 2nd Avenue.[42] When the service line to Building 2 was pressure tested

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[39] A *flow rate test* measures the volumetric flow of gas over a time interval at a specific temperature and pressure.

[40] The maximum allowable operating pressure of the Cherry Street main was 60 psig.

[41] The tested section was approximately 20 feet in length and located at the intersection of Cherry Street and South 2nd Avenue. This portion of the Cherry Street main encompassed the transition from 2-inch steel to 1.25-inch Aldyl A.

[42] A *riser* is a pipe that connects underground piping to aboveground piping and assets, such as the gas meter.

on April 26, it lost about 5 psig in 5 minutes of testing, indicating a relatively large leak. Further pressure testing confirmed the presence of a leak in the segment that contained the active and retired service tees to Building 2. Pressure testing also revealed a small leak in the service line to Building 2. The pipeline and its riser were sent to the NTSB Materials Laboratory for further testing. (See section 1.6.2.3.)

1.6.1.6 Air Flow Velocity and Smoke Tests

On April 24, a representative from the Occupational Safety and Health Administration (OSHA) conducted air flow velocity measurements to determine the rate of air flow between Buildings 1 and 2 in their postaccident conditions. The representative took the measurements from the Building 1 basement at the opening of the two underground chocolate pipe conduits. The average baseline air flow velocity around the pipe conduits was 2 feet per minute. When the Cherry Street gas main was pressurized with air to 26 psig, air flow velocity measurements at the conduits increased from baseline, ranging 8.8 to 21 feet per minute.

The Pennsylvania State Police deputy fire marshal connected a smoke generator to the chocolate pipe conduits in the basement of Building 2 and started it up to investigate whether gas could flow between the two buildings. Smoke was observed in the basement and on the third floor of Building 1.

To further test the interaction between the chocolate pipe conduits and the ground around the gas pipelines, the NTSB used rags to block the spaces in the conduit opening around the chocolate pipes in the Building 1 basement. When the smoke generator was restarted in the Building 2 basement, smoke emanated from the ground near the Building 2 foundation and the gas service line. (See figure 10.)

Figure 10. Smoke from conduit visible near gas service line to Building 2.

1.6.1.7 Excavation

On April 26, the excavation of Cherry Street just south of Building 2 exposed the natural gas pipelines and other components, along with Palmer's chocolate conduits, steam pipe, and condensate line, shown in figure 11.

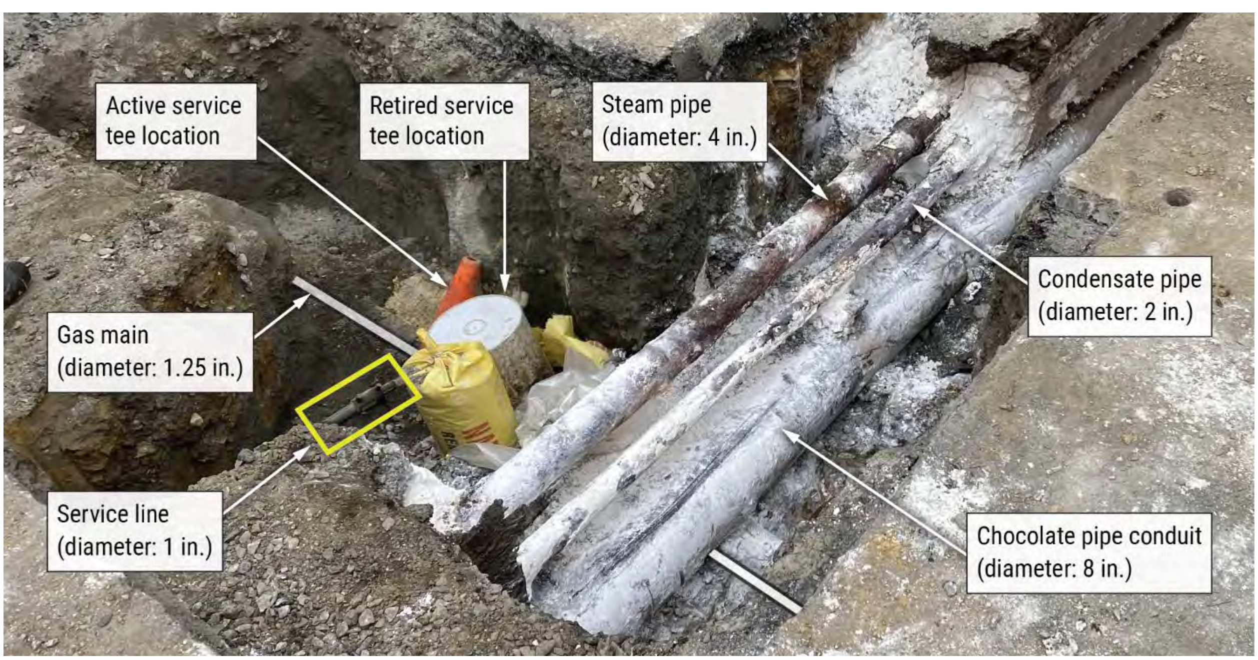

Figure 11. Excavation of pipes at the accident location.

As the retired service line to Building 2, which was under pressure, was being unearthed, the NTSB observed that air was coming from the top of the retired 1982 service tee. The service tee's cap and a portion of its insert were missing.[43] The NTSB oversaw as UGI sifted the soil from the excavation but did not recover the cap or the upper portion of the insert; the lower portion of the insert remained with the service tee. The NTSB removed the remaining portions of the retired service tee, along with the section of 1.25-inch-diameter Aldyl A gas main to which the tee had been attached, and sent them to the NTSB Materials Laboratory for evaluation (see section 1.6.2).

The NTSB also removed a marker ball, which UGI had placed next to the Building 2 service tees as part of the 2021 replacement project, and retained it for examination at the NTSB Materials Laboratory.[44]

1.6.1.8 Visual Inspections

Also on April 26, the Pennsylvania State Police deputy fire marshal visually inspected what remained of the Building 2 basement. Investigators in the basement of Building 1 pointed a flashlight through the chocolate pipe conduits toward the Building 2 basement to see whether air flow through the conduits could have been obstructed by insulation or other material. The deputy fire marshal observed light through the conduits. (See figure 12.)

[43] The UGI field crew would have reinstalled the cap of the retired service tee to seal it upon installation of the new Building 2 tee in 2021.

[44] A *marker ball* is a hollow sealed sphere, made from a thermoplastic polymer and partially filled with a leveling fluid, that is used to identify plastic underground utilities.

Figure 12. A view of one of the chocolate pipe conduits from the Building 2 basement.

Investigators also observed corrosion and a through-wall crack of approximately 4 inches on the underground steam pipe that had been exposed in the NTSB's postaccident excavation. This pipe was located about 15.5 inches above and 23 inches to the west of the retired service tee.[45] Visual observation of the length of the exposed pipe showed external corrosion, which can also be seen in figure 11. The NTSB oversaw as UGI removed surface rust from the steam pipe (outside of the section containing the through-wall crack) to take wall thickness measurements. The thickest measurement was 0.216 inches and the thinnest was 0.148 inches. The

[45] The pipe was between 25 and 30 feet from the Building 1 service tee.

cracked section of the steam pipe was sent to the NTSB Materials Laboratory for examination (see section 1.6.2.5).[46]

1.6.2 Laboratory Examinations and Research

From June 26 to June 30, 2023, the NTSB examined the natural gas piping, tees, steam pipe, and related pipeline components retained from the accident scene. Detailed descriptions of these examinations are below.

1.6.2.1 Aldyl A Retired Service Tee

The NTSB examined the retired service tee's tower, which is the cylindrical barrel on the top of the tee that houses the cutter. The tower was a two-piece assembly consisting of a cylindrical Delrin insert surrounded by an Aldyl A outer shell. The inner surface of the insert was threaded to guide the internal cutter and to secure the service tee cap, and the outer surface contained longitudinal and circumferential ribs. The Aldyl A shell was molded and formed around the insert, with corresponding grooves that interlocked with the ribs on the insert to resist axial and rotational movements during cutting and capping.

A visual examination of the retired service tee revealed a 1.9-inch fracture through its polyethylene tower shell, from the top of the tower nearly to its base. (See figures 13 and 14.) The fracture was centered in one of the longitudinal grooves located on the inner surface of the shell and had initiated at a line-like impression in the groove consistent with a mold parting line.[47]

[46] The NTSB observed a subsurface white powder surrounding the Palmer steam pipe and other assets that had been exposed. A third-party laboratory examination determined that the powder was predominantly calcium carbonate. The NTSB investigation did not determine the source or purpose of the powder.

[47] A *mold parting line* is a line left by two halves of a mold.

Figure 13. Longitudinal fracture in retired service tee.

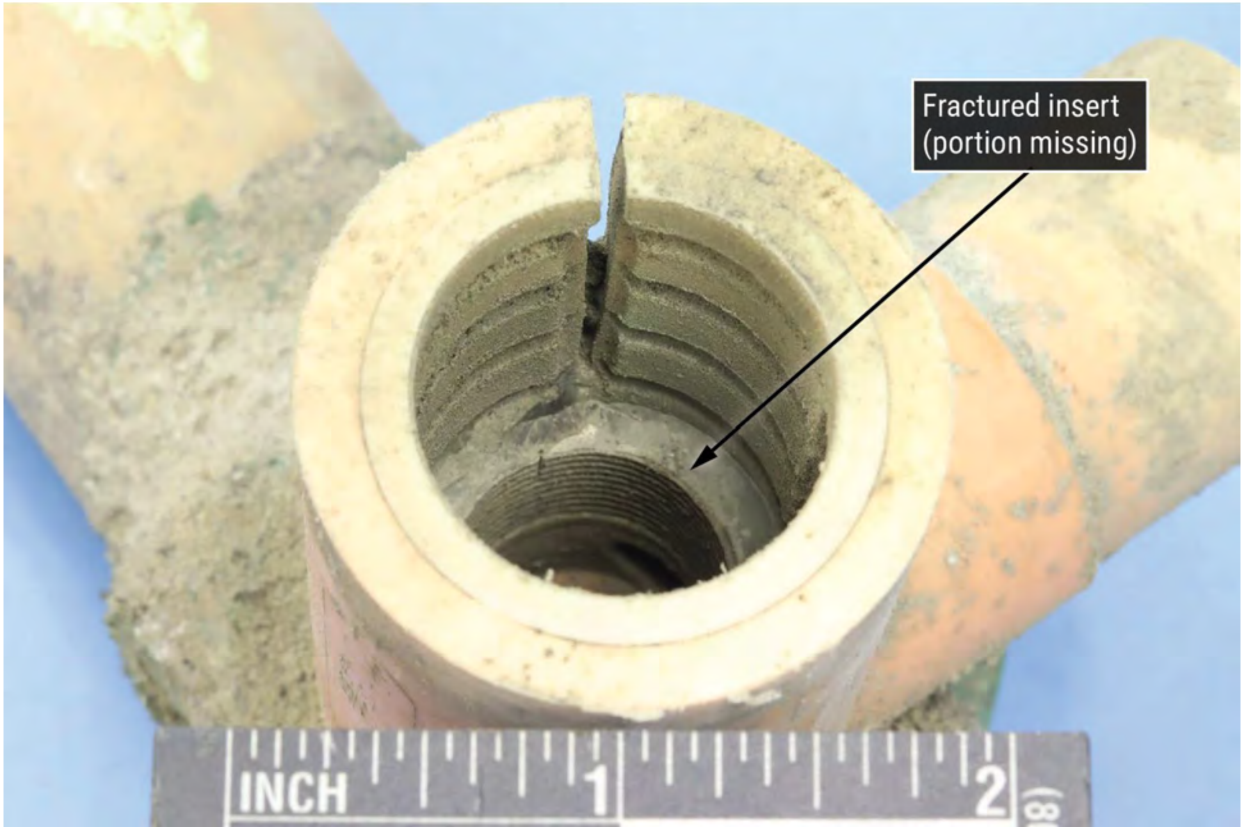

Figure 14. Interior of retired service tee tower with top portion of Delrin insert missing.

One of the fracture surfaces was cleaned and examined. It exhibited features consistent with fracture initiation from slow crack growth.[48] The slow crack growth region originated on the interior surface of the shell, between 0.325 inches and 0.430 inches from the top of the tower. From there it progressed through the wall, to the top of the tower and toward its base. Toward the top of the tower, the fracture surfaces were flat, comparatively featureless, and exhibited fibrils.[49] Near the base, the flat, featureless regions of the fracture surface transitioned to hackle consistent with a fast fracture following slow crack growth.[50] (See figure 15.)

[48] *Slow crack growth* is a time- and temperature-dependent type of polymer failure occurring under low stress levels.

[49] *Fibrils* are filaments of polymeric material that form bridges between opposing crack faces.

[50] *Hackle* refers to line-like features on a fracture surface that run in the local direction of cracking.

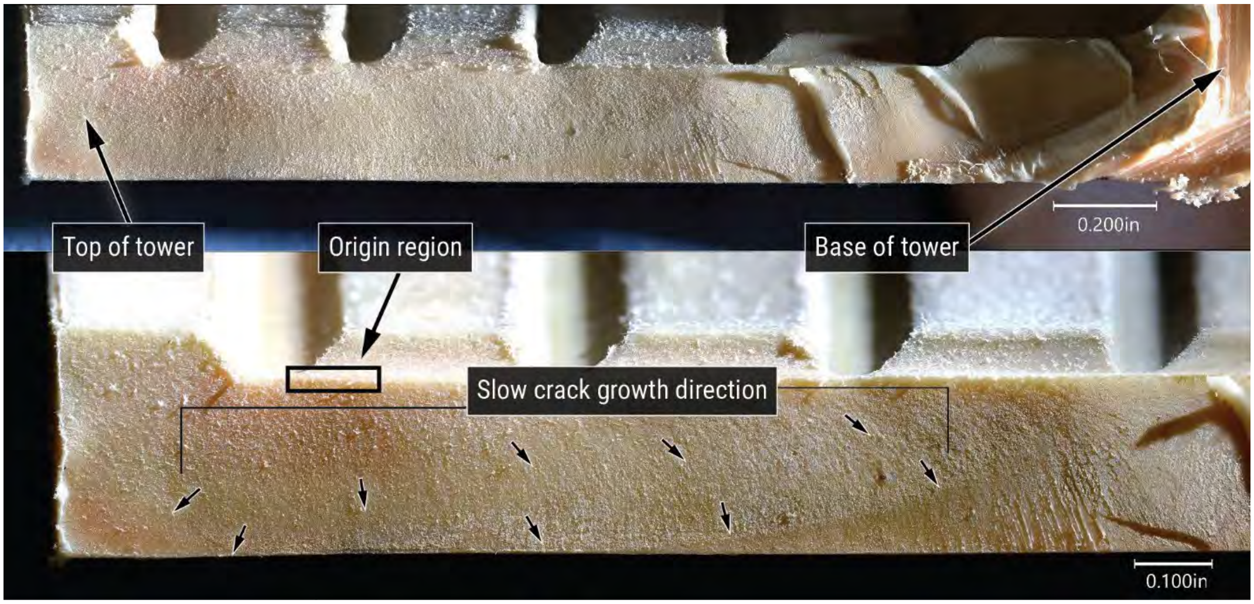

Figure 15. (*Top image*) Longitudinal fracture from top to base of tower. (*Lower image*) Detailed image of slow crack growth region.

A visual assessment of the retired service tee's Delrin insert showed that it too was fractured, with a transverse fracture located near the bottom of the insert. A region of the fracture, which was closest to the steam pipe before the accident, had a crazed and fibrous appearance.[51] Elsewhere, the fracture had a granular and porous appearance. The outer surface of the insert showed surface cracking and volume loss, which is visible in figure 16 along with the fracture origin. This was the first accident NTSB has investigated involving a longitudinal fracture from thermal degradation of an Aldyl A service tee with Delrin insert.

[51] *Crazing* is a network of fine cracks that often precede fracture in some polymers.

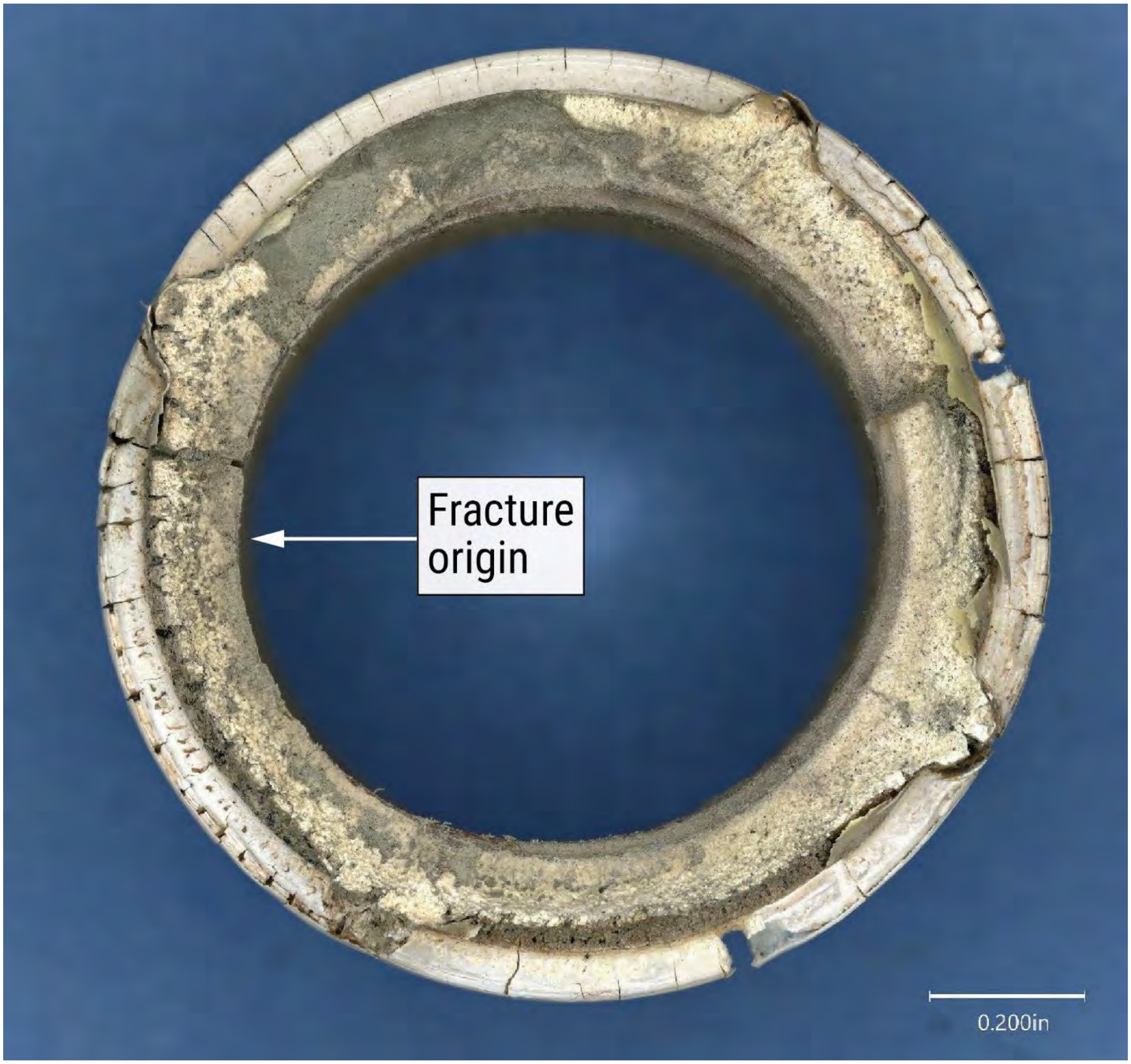

Figure 16. Image of fracture surface on Delrin insert for retired service tee.

1.6.2.2 Aldyl A Gas Main

X-ray CT scans revealed a small crack in the 1.25-inch Aldyl A Cherry Street main, located underneath the Building 2 active service tee saddle, where bubbles had appeared in an earlier leak test.[52] The NTSB observed that the crack was visible on the inner pipe surface, measured 0.39 inches in length, and was centered just upstream of the tee outlet. Examination of the fracture surface indicated that the

[52] (a) The saddle of the active service tee had been fused to the main but also clamped to it by an undersaddle. (b) This leak test measured a flow rate of 0.6 standard cubic feet per hour.

crack had initiated on the outer surface of the pipe and that it exhibited progressive start–stop and slow crack growth features.

1.6.2.3 Polyethylene Service Line

The NTSB examined the active Building 2 polyethylene service line, in which pressure testing had revealed a small leak, and the service line's flexible steel and rubber riser. They observed a cut where the wall of the service line had impinged upon a sharp, deformed edge on the flexible riser's downstream fitting. Stretching and deformation of the flexible riser led to the formation of the sharp edge. These mechanical damage features were consistent with explosion damage.

1.6.2.4 Building 1 Service Tee

The NTSB examined the service tee to Building 1, which like the Building 2 service tee had been installed in 1982 and was composed of Aldyl A material with a Delrin insert. The tower shell, insert, and cap did not show cracking or material decomposition.

1.6.2.5 Steam Pipe

The NTSB examined a 46-inch segment of the steam pipe that had been recovered from the accident site. The pipe was made of steel and was 4 inches in diameter, with a wall thickness of between 0.20 and 0.22 inches.[53] The sample of pipe examined by the NTSB displayed varying levels of wall thickness loss. The steam pipe had been deformed by shear forces (acting on opposite sides of the pipe) near the middle of the segment, with the direction of shear downward.

Within the sheared region, the pipe was corroded on its outer surface and cracked. Within the examined section, the smallest wall thickness measurement, 0.038 inches, occurred near the edge of one of the cracks.[54] The cracks were located on the east-facing side of the pipe, facing the Building 2 retired tee, and were inclined relative to the longitudinal axis of the pipe. The longest crack was about 4

[53] These measurements are consistent with 3.5-inch schedule 40 pipe (nominal pipe size).

[54] This thickness was 17% of the pipe's initial (nominal) wall thickness.

inches long and had formed along a compressive buckle within the sheared region.[55] Two shorter cracks branched off the 4-inch crack. (See figure 17.)

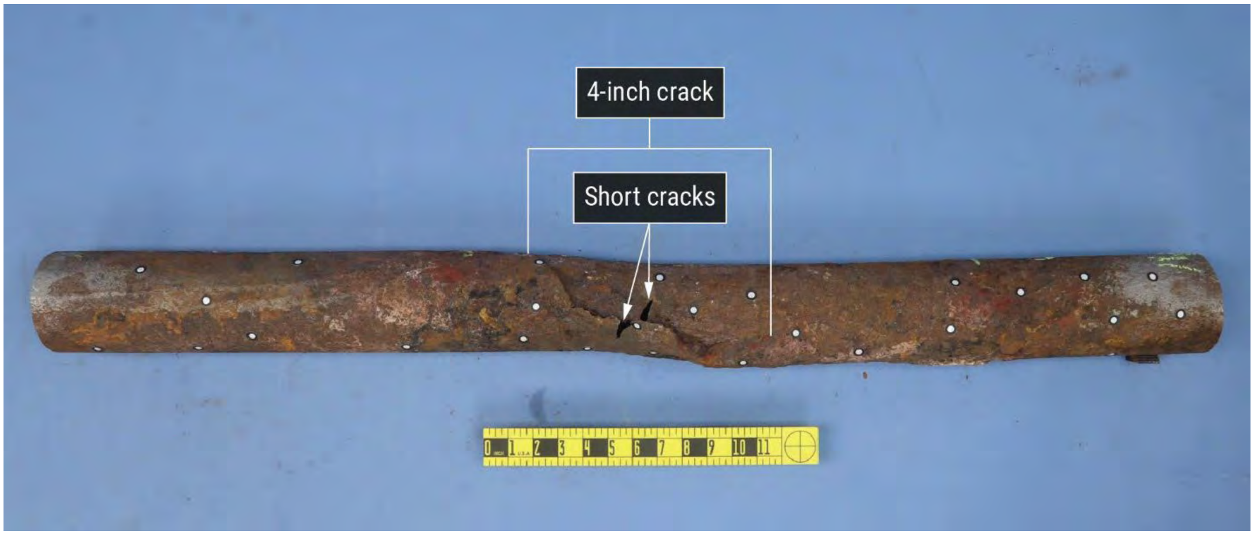

Figure 17. Through-wall cracks in steam pipe.

1.6.2.6 Marker Ball

The plastic marker ball retained from the accident site was observed to have collapsed inward from both the top and the bottom. The seam that had sealed the two halves of the marker ball had also separated, allowing much of the liquid contents of the ball to escape.

1.6.2.7 Simulation

The NTSB Materials Laboratory conducted a finite element simulation to study the effect on the surrounding environment of an intact steam pipe—one with no crack—operating at 10 psig, with modeled ground temperatures of 40°F and 60°F from regional historical data. For the range of ground temperature and soil properties studied and for the likeliest condition of steam flowing unassisted through the pipe, the temperature at the location of the retired service tee was 27°F to 40°F above the ground temperature.

1.6.2.8 Photographic Study

As UGI worked on the service line replacement project on Cherry Street on February 16, 2021, a Palmer employee took a photograph of the work.

[55] This sort of *buckling* or outward deflection occurs when a material is subjected to compressive stresses beyond a certain level.

(See figure 18.) The NTSB reviewed the photograph to estimate the extent and location of excavation with mechanized equipment, and the photographic study showed that the excavation took place around the same location as the crack in the steam pipe. (See section 1.6.2.5.) The study showed that the west edge of the excavation was located within about 1 foot of the location of the steam pipe and that the excavation extended south of the location of the crack. The study was unable to determine the depth of the excavation.

Figure 18. UGI crew during service line replacement project, 2021. (Photo courtesy Palmer.)

1.7 Regulations, Advisories, and Standards

1.7.1 Pipeline and Hazardous Materials Safety Administration

Federal pipeline safety regulations are found in Title 49 *Code of Federal Regulations* (*CFR*) Parts 190 through 199, with 49 *CFR* Part 192 covering the minimum federal safety standards for transportation of natural and other gas. For the gas distribution system involved in this accident, Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations apply to main and service lines up to the outlet of the gas meter. PHMSA regulations include requirements for the gas distribution operator to manage the integrity of its system, maintain its valves, and conduct public awareness programs. The agency also issues advisory bulletins to provide guidance and awareness to the industry on specific safety concerns.

Federal regulations specify location, accessibility, and maintenance requirements for distribution line valves. Natural gas pipeline operators must determine which of their valves are necessary for operating or emergency purposes. PHMSA specifies that the valves used for operating or emergency purposes must be placed in a "readily accessible location," and those that are necessary for the safe operation of a distribution system must be maintained annually, with time between inspections not to exceed 15 months.[56]

Federal regulations require natural gas pipeline operators to maintain a public awareness program that meets criteria in the first edition of the American Petroleum Institute's (API) Recommended Practice (RP) 1162, which offers guidance on public awareness program development, stakeholder audiences, message content, delivery methods, documentation, record keeping, and program evaluation.[57] The first edition of API RP 1162, released in 2003, is incorporated by reference into the federal regulations; the standard is now in its third edition. The four stakeholder audiences outlined in RP 1162 are (1) the affected public, (2) local and state emergency response and planning agencies, (3) local public officials and governing councils, and (4) excavators.[58] According to RP 1162, a public awareness program must

[56] See 49 *CFR* 192.181, "Distribution line valves," and 49 *CFR* 192.747, "Valve maintenance: distribution systems."

[57] See 49 *CFR* 192.616, "Public awareness."

[58] The affected public defined by the first edition of API RP 1162 includes residents of both single- and multifamily structures as well as "places of congregation," or places where people assemble or work on a regular basis.

communicate to the affected public that they live or work near a pipeline, how to recognize and respond to a pipeline emergency, and protective actions in the event of a natural gas leak. Bill stuffers, or inserts included in monthly gas bills, are specified as a baseline (that is, must be conducted at minimum) public awareness activity in RP 1162 with a baseline frequency of twice annually.[59] Targeted distribution of print materials is specified as a supplemental activity. For the emergency officials stakeholder group, the standard specifies once-yearly print materials or group meetings as a baseline public awareness activity.

In November 2002, PHMSA issued an advisory bulletin notifying pipeline operators of the susceptibility of older plastic pipe, like Aldyl A, to premature brittle-like cracking.[60] In the bulletin, PHMSA stated that "piping installed in areas with higher ground temperatures or operated under higher operating pressures will have a shorter life" (PHMSA 2002). An updated advisory bulletin was issued on August 28, 2007, and added Delrin-insert tapping service tees to the list of pipe materials that are susceptible to brittle-like cracking (PHMSA 2007).

1.7.2 Pennsylvania Public Utility Commission

The PA PUC enforces 49 *CFR* Part 192 regulations for all gas distribution operators in the state and imposes additional requirements through state code. The PA PUC has inspected UGI for safety compliance with the Pipeline and Hazardous Materials Safety Administration's minimum federal safety standards.

The PA PUC reports for UGI's distribution integrity management program (DIMP) showed that for the years 2018, 2020, 2021, and 2022, the PA PUC found no compliance concerns with UGI's program.[61] The 2019 inspection found that UGI's DIMP did not comply with federal and state DIMP requirements to identify threats, evaluate and rank risks, and identify and implement measures to address risks.

[59] Natural gas distribution companies frequently mail *bill stuffers*, or printed brochures, along with customer gas bills.

[60] *Brittle-like cracking* initiates in the pipe wall but does not immediately result in a full break; it leads to stable crack growth at relatively low stress levels and often correlates with slow crack growth.

[61] A DIMP is a performance-based program resulting from the Pipeline Inspection, Enforcement and Protection Act of 2006, which requires pipeline operators such as UGI to collect and manage data on pipeline integrity.

1.7.3 Occupational Safety and Health Administration

Federal OSHA regulations are found in 29 *CFR* Chapter XVII and apply to most private-sector employers and workers in all 50 states (including Palmer in Pennsylvania), the District of Columbia, and other US jurisdictions. OSHA's authority generally applies to private-sector employers, but it allows states to assume responsibility for occupational safety and health for the private sector as well as for state and local employers and workers under an OSHA-approved state plan. Pennsylvania is a federal OSHA state, meaning it does not have an OSHA-approved state plan.

OSHA requires that employers have an emergency action plan that includes procedures for employees to follow during workplace emergencies.[62] The plan must include escape procedures and routes and accountability of employees after an emergency evacuation. Title 29 *CFR* 1910.38, "Emergency action plans," only applies when referenced in another OSHA standard.[63] Two OSHA standards referencing 29 *CFR* 1910.38 applied to Palmer at the time of the accident: one standard states that companies must maintain an employee alarm system, and the other states that companies must have fire extinguishers.[64]

1.7.4 Codes

The Commonwealth of Pennsylvania requires that all its boroughs follow the Pennsylvania Uniform Construction Code for all buildings and structures within a borough. At the time of the accident, West Reading had adopted the Pennsylvania Uniform Construction Code and the 2015 edition of the International Fire Code (IFC), and Pennsylvania had adopted the 2018 edition of the International Building Code, which applies to the safe construction of buildings or structures and references parts

[62] See 29 *CFR* 1910.38, "Emergency action plan."

[63] Title 29 *CFR* 1910.38(a) states the following: "Application. An employer must have an emergency action plan whenever an OSHA standard in this part requires one."

[64] See 29 *CFR* 1910.157, "Portable fire extinguishers," and 29 *CFR* 1910.164, "Fire detection systems." OSHA defines an employee alarm system as "any piece of equipment and/or device designed to inform employees that an emergency exists or to signal the presence of a hazard requiring urgent attention." See [OSHA's Evacuation Plans and Procedures eTool]().

of the 2018 editions of the IFC and the International Fuel Gas Code (IFGC).[65] The International Code Council (ICC) administers the IFGC and IFC.[66] The IFC requires a fire safety and evacuation plan, but not a natural gas emergency procedure. IFGC addresses the design and installation of gas-fueled appliances and fuel gas systems past the outlet of the gas meter, which are not covered by federal or state transportation safety standards. Like the IFGC, the National Fuel Gas Code, referred to as National Fire Protection Association (NFPA) 54, provides minimum safety requirements for the design and installation of fuel gas piping systems and is administered by the NFPA, a nonprofit organization that issues widely adopted consensus codes and standards designed to minimize the risk and effects of fire. NFPA committees are responsible for revision of the codes and standards through an American National Standards Institute–accredited process. NFPA 54's Annex D, which is included only for informational purposes and does not contain requirements, lists immediate actions to be taken when natural gas is detected inside a building, including clearing the area of all occupants, eliminating ignition sources, shutting off gas supply, and calling 9-1-1.[67] NFPA also has a fire code, NFPA 1, which contains a fire safety and evacuation plan but not one specific to natural gas.

[65] (a) *Building codes* are a set of requirements for building design, construction, operations, and maintenance that are officially adopted and may be enforced by a jurisdiction. Palmer's West Reading facilities were built before the development of the borough's codes department. In general, buildings built to the codes of their time can remain in their original state even as codes are updated. (b) The IFC is primarily a maintenance code addressing fire safety within a building.

[66] The ICC is accredited under the American National Standards Institute and develops these codes through technical committees.

[67] Pennsylvania has adopted NFPA 54 only for industrial and commercial use of propane and other liquid petroleum gases. The standard did not apply to Palmer, because the company did not use these chemicals in Buildings 1 and 2. For more, see *Pennsylvania Code* Title 34, Chapter 13.4, "Adoption of National Standards."

1.8 Plans, Procedures, and Programs

1.8.1 R.M. Palmer

1.8.1.1 Emergency Response Procedures

Palmer's emergency plan manual, which the company referred to as the Red Book, addressed food and employee safety for all Palmer facilities.[68] The Red Book included an emergency contact list with phone numbers for federal, state, and local law enforcement; the National Response Center; and utility companies such as UGI, Palmer's contact for natural gas emergencies. The Red Book also contained maps indicating emergency shut-off locations for all utilities within Palmer's facilities, including the gas shut-off in Building 2, which was located on the inside wall of the basement facing Cherry Street. The Red Book did not include a procedure for when to call UGI or when or how to shut off gas. Palmer maintenance employees interviewed by the NTSB stated they had not been trained in gas leak detection.

The company's crisis management plan, part of the Red Book, listed various potential threats to business operations, such as fire, power failure, storm damage, flood, civil unrest, and equipment failure. A natural gas emergency was not listed among the threats in the crisis plan, and the Red Book did not contain procedures specifically addressing natural gas emergencies. Procedures were included for facility evacuation in general emergency situations. Evacuation was prompted by alarms triggered by activation of sprinklers, manual pull stations, or smoke and heat detectors. The Red Book directed employees to "stop all activities and proceed to the nearest exit and then to their designated muster point[s]" and specified that evacuation drills should be held "periodically." The Red Book listed muster points and evacuation route maps for Buildings 1 through 4.

In interviews with the NTSB, the Palmer chief executive officer (CEO) and vice president of operations and technical services (VP) considered a natural gas leak a low risk at the accident location, stating that the buildings' natural gas use was relatively minimal and that if a leak were to occur, employees would have "time to react to things."

[68] Palmer developed the employee safety guidelines in the Red Book in 2005, using guidance from OSHA, the National Institute for Occupational Safety and Health, the US Environmental Protection Agency, the Pennsylvania Department of Environmental Protection, the NFPA, and Industrial Risk Insurers. At the time of the accident, the Red Book had been most recently revised in August 2022.

1.8.1.2 Safety Training

According to interviews with Palmer employees, their employee safety training mostly pertained to performing job tasks. Palmer did provide some employees additional training on safety equipment like fire extinguishers. Most employees interviewed by the NTSB recalled familiarity with the evacuation procedure in the Red Book and reported that the company conducted annual fire drills. The NTSB's review of Palmer records related to fire and emergency evacuation drills showed that evacuation times varied, with 5 minutes from the pull of the fire alarm as the shortest evacuation time.

The Palmer employees interviewed by the NTSB stated that they were never trained on how to respond to a natural gas emergency. When asked by the NTSB about experience with or knowledge of how to respond to a natural gas odor, several Palmer employees cited personal experience with or knowledge of natural gas in their homes or those of their neighbors.

1.8.1.3 Equipment Maintenance

The Palmer CEO and VP stated that maintenance department mechanics were responsible for repair and maintenance of most production equipment. They told the NTSB that when employees identified an issue, they were to report it to the maintenance department, which decided whether the issue would be addressed by in-house mechanics or by hiring a contractor. The Palmer CEO and VP further stated that these mechanics generally were trained on the job (meaning very little formal or classroom training on their job duties) and that, because maintenance and repair of natural gas appliances fell outside the maintenance department's scope of work, it was typically performed by a contractor. The Palmer CEO indicated, however, that Palmer maintenance staff "might check for a leak."

The NTSB interviewed a Palmer chocolate unloader, who recalled smelling a gas odor near the boiler house east of Building 1 on March 23, 2023, the day before the accident. He then checked the boiler house gas meter for leaks and found none. The chocolate unloader told the NTSB that checking for leaks was not a standard procedure of Palmer's, but one based on his own personal maintenance experience.

Palmer had a safety committee made up of employees and managers from various shifts and job titles that met monthly to discuss potential safety issues with equipment or operations and how to fix these issues.[69] According to Palmer management, inspections for tripping hazards, machine guards, blocked emergency exits, and other issues took place weekly. Employees could also raise safety issues or potential issues to the committee. The NTSB interviewed Palmer employees who had attended safety committee meetings over the years, and none recalled discussing gas operations or emergency response to natural gas emergencies in the meetings.

The contractor who maintained Palmer's natural gas–fueled appliances reported to the NTSB that they had not performed any work on the appliances in the 3 years before the accident.

1.8.2 UGI Corporation

1.8.2.1 Procedures

UGI's *Gas Operations Manual* (GOM) outlined procedures for first- and second-party excavation activities.[70] The GOM did not require crews to contact PA One Call when using "soft dig" methods like vacuum extraction or shallow tilling but suggested crews use the service to locate other utilities in the area. The GOM did require crews to contact PA One Call when using mechanical equipment (for example, excavators, jackhammers, or pavement saw cutters).

UGI's *Emergency Plan* included emergency procedures for UGI personnel to take when reacting to an explosion, fire, or both that may be caused by a release of gas from UGI assets. The procedures covered both indoor and outdoor leaks and specified actions UGI personnel must take when arriving on scene, contacting local authorities, and dealing with natural gas assets involved in a release. The plan specified that if it is unclear which valves need to be closed, a UGI first responder must contact central dispatch, a senior area engineering manager, or the on-call engineering leader to determine which valves to close and other steps to isolate the system.

[69] Palmer's natural gas–fueled equipment and appliances, described earlier in this section, fell under the scope of the safety committee.

[70] *First-party excavation activities* are conducted in a pipeline's right-of-way by the pipeline operator's own personnel. *Second-party excavation activities* are conducted by a contractor.

1.8.2.2 Integrity Management

Integrity management (IM) programs identify, assess, and manage pipeline safety risk. In pipeline IM plans, the risk of an adverse event is the product of both its likelihood and its consequences. IM is a continuous, iterative process in which information on risk is gathered, risk is reduced or mitigated, and risk is reevaluated, with the IM process evolving over time. In some cases, as with UGI, IM programs are required by regulation.[71]

UGI used incident data maintained by PHMSA as its system of record for incident information. Before March 24, 2023, UGI attributed no incidents to Aldyl A service lines or mains. According to PHMSA data, UGI reported nine significant incidents involving the company's assets since 2010. Aside from the accident discussed in this report, UGI attributed the other incidents to damage from natural force, excavation, or other outside force; incorrect operation; and material failure.[72]

1.8.2.2.1 Risk Management

UGI IM staff told the NTSB that the program managed pipeline risks by completing targeted assessments; reducing risks through repairs, replacements, or other actions; and continual evaluation and improvement. UGI required periodic inspections and patrols but did not require any additional integrity assessments on its assets in the vicinity of the accident site.[73]

UGI's DIMP was centrally managed and administered. Inspections required by UGI's GOM were the primary data sources that UGI personnel used to collect information on distribution assets. The DIMP used a relative risk model for evaluating gas mains to guide decisions about asset replacement. The DIMP also used quantitative and subject-matter expert (SME) model (that is, qualitative evaluation) to identify asset risks.

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[71] UGI is required by 49 *CFR* Part 192 Subpart P to have a gas DIMP.

[72] One of the material failure incidents occurred on July 2, 2017, in Millersville, Pennsylvania, and involved a plastic service line installed in 1998. The other occurred on December 25, 2020, in Swiftwater, Pennsylvania, and involved a plastic main installed in 2019.

[73] *Integrity assessments* are elements of an IM program by which operators evaluate the condition of pipelines or assets subject to identified threats and take actions to mitigate the threats, if identified. UGI had reviewed and evaluated the threats in its assets near the Palmer facilities and had determined no integrity assessments were warranted.

UGI DIMP documents listed the *Guide for Gas Transmission, Distribution, and Gathering Piping Systems* (GPTC Guide), managed by the Gas Piping Technology Committee (GPTC), as one of the references used to develop and maintain this program.[74] The GPTC Guide describes heat sources and steam pipes as hazards to plastic gas mains and services that should be evaluated. The guide also provides information on the evaluation of plastic gas main and service line installations near heat sources to determine mitigative measures. The GPTC Guide further notes that to assess the applicable threats and risks to natural gas pipeline systems, a pipeline operator's DIMP must identify the characteristics of the pipeline's design and operations along with significant environmental factors. A DIMP must also collect information on steam pipes or other heat sources causing elevated temperatures and must provide the information to the IM program for evaluation.

UGI's system of record for natural gas main data and leak survey results was Smallworld GIS, and its system of record for service lines was an in-house gas service web application. At the time of the accident, UGI had captured no data in these systems about privately owned subsurface assets. UGI likewise did not record any damage to privately owned assets in any of its databases; further, PA One Call required excavators to report such damage, and if UGI reported such damage, the damage would be logged by UGI's claims team. UGI training did not provide any instruction to field personnel on steam lines or other private assets as possible threats to natural gas assets.

1.8.2.2.2 Risk Models

At the time of the accident, UGI used three risk models to identify and evaluate risks to the pipeline distribution system: (1) the Optimain model, used exclusively for prioritizing gas main replacement; (2) the data-driven risk model (DDRM); and (3) the SME risk model; the latter two models were used to identify risk in gas mains and service lines. The threat categories used in UGI's risk model were (1) corrosion; (2) natural forces; (3) excavation damage; (4) other outside force damage; (5) pipe, weld, or joint failure; (6) equipment failure; (7) incorrect operation; and (8) other, such as exceeding service life.[75]

[74] GPTC is a consensus group comprised of industry representatives and government regulators that develop guidance for the natural gas operators on practices and procedures to comply with requirements of federal pipeline safety regulations.

[75] Operators are required by 49 *CFR* 192.1007(b) to consider specific threat categories in their IM programs.

The DDRM was a quantitative model that estimated the probability and consequence of failure for asset groups based on the type of asset, pressure, material, and other factors. UGI used the SME risk model to validate the findings of the DDRM and, when applicable, to evaluate risk at a more granular level than was possible in the DDRM.

In the SME model, a total risk score was derived from an SME assessment of a DDRM asset group and threat to pipeline integrity. SMEs determined probability factors for asset failure based on whether each threat contributed to failure and the extent to which the threat had been observed by UGI. The model also assigned a consequence factor, developed by UGI to amplify the magnitude of the consequence for identified asset types. UGI had not developed a consequence factor for Aldyl A fittings, evaluating the threat and consequences of Aldyl A to be the same as other polyethylene fittings.

After the accident, UGI provided the NTSB with an estimation of the extent (amount) of Aldyl A in its system.[76] Reported Aldyl A and potential Aldyl A are shown in table 3.[77]

Table 3. Estimated UGI Aldyl A and total assets.

Material Category	Main (miles)	Active Services (number of lines)	Retired Services (number of lines)
Reported Aldyl A (1965–2001)	32	1,211	48
Potential Aldyl A (including reported installation dates of 1965–1986)	636	86,891	6,482
Total, any material	12,337	617,069	Unknown

[76] UGI estimated the amount of Aldyl A by identifying in Smallworld GIS and its gas service web application all DuPont-manufactured pipe installed from 1965 to 1991, Uponor-manufactured pipe installed from 1991 to 2001, or pipe classified with Aldyl A as its material type.

[77] Historical records of natural gas pipeline operators often indicate only that a pipe material is polyethylene and do not necessarily specify the type of polyethylene. In its review of records, UGI identified situations in which piping may be Aldyl A but was not reported as such, referring to these as "potential Aldyl A."

Before the explosion, UGI had studied records of leaks and failures associated with the Aldyl A tees with the Delrin insert. The study concluded that these tees had a history of leakage from the black service tee caps. It further stated that leaks had been found through normal operations, leak surveys, and odor complaints and had not resulted in serious consequences.

UGI stocked repair kits for Aldyl A service tees, which modified the tees and eliminated the black caps, but did not mandate that crews use the repair kits whenever they encountered Aldyl A.[78] After the accident, UGI estimated that from 2020 to 2023, a total of 3,193 Aldyl A repair kits had been issued to field crews.

1.8.2.3 Pipeline Safety Management System

Representatives from UGI stated that the company began implementing their pipeline safety management system (PSMS) in 2015. In 2019 and again in 2024, UGI used a self-assessment model to evaluate its PSMS maturity, which UGI recorded as "developing" with several elements implemented.[79] In 2022, UGI established a PSMS Governance Committee that focused on continuous improvement by addressing priorities within each PSMS element.

1.8.2.4 Public Awareness Program

UGI's public awareness program in the West Reading area informed its customers about the natural gas distribution and transmission system, signs of a pipeline leak, and what to do if a gas odor is detected. A section of UGI's website titled "Smell Gas? Act Fast!" contained a contact number for UGI and instructions to leave the area and to call UGI, 9-1-1, or both.

A UGI representative provided the NTSB a summary of its public awareness efforts for Palmer, specifically for Buildings 1 and 2. These included mailings of scratch-and-sniff brochures in both English and Spanish to Building 1 in December 2022 and January 2023, a February 2020 advertisement in the *Reading Eagle*, and booths at a Reading Phillies game in August 2018 and at Junior League of Reading touch-a-truck events from 2016 to 2019. Ongoing efforts included gas safety classes

[78] UGI stated one of its regions (UGI North) had installed repair kits anytime crews encountered Aldyl A service tees with black caps while working on replacement projects.

[79] These include hiring a full-time PSMS lead, updating its Governance Committee charter, and considering PHMSA advisory bulletins and NTSB recommendations into its incident investigations.

at local schools, on-hold messaging at the UGI call center, social media posts, and bill stuffers.

The NTSB reviewed UGI's data on the effectiveness of its public awareness messaging to stakeholder audiences.[80] The data indicated that 62% of respondents recalled receiving information from a pipeline company within the past 2 years, and 36% did not. A UGI survey from 2020 indicated that, within the stakeholder category of the affected public, about 31% had read all or some of UGI's natural gas safety bill stuffer, 21% had "just scanned it," 38% did not know whether they had read it, and 8% had not read it. Data from a 2022 UGI report on its public awareness program effectiveness showed that 41% considered themselves somewhat well-informed about pipelines in their community, 31% considered themselves either not at all or not too informed, and that 27% considered themselves very well-informed. The same report contained data on what respondents would do in a pipeline emergency, with 86% of respondents stating they would call 9-1-1, 62% stating they would flee the area, and 42% stating they would call the pipeline company.[81]

1.9 Postaccident Actions

1.9.1 Occupational Safety and Health Administration Investigation

OSHA opened an investigation into the accident and issued Palmer two serious and six other-than serious violations.[82] These violations are summarized in table 4.[83]

[80] These data are contained variously in UGI's 2020 Effectiveness Measurement, UGI 2022 Effectiveness Measurement, and UGI Four-Year Evaluation (2020).

[81] Respondents were able to select more than one answer.

[82] (a) A *serious violation* as designated by OSHA exists when a workplace hazard could cause an accident or illness likely resulting in death or serious physical harm, unless the employer did not know or could not have known of the violation. *Other-than-serious* is a violation directly related to job safety and health but not serious in nature. (b) Palmer contested the violations.

[83] OSHA initially cited Palmer under the general duty clause of the Occupational Safety and Health Act of 1970 for failing to evacuate workers during a natural gas leak that resulted in an explosion causing multiple fatalities. During abatement of the citations, OSHA withdrew the general duty citation and replaced it with a citation under the Emergency Action Plan standard, 29 *CFR* 1910.38, as described in section 1.7.3. As part of the settlement agreement, Palmer agreed to several actions, including a specific natural gas leak procedure and training of its employees. It is stated in the agreement that these actions were not required of the company before the accident.

Table 4. Palmer OSHA-issued violations.

Regulation	Type	Basis
29 *CFR* 1910.38(f)(2)	Serious	Palmer failed to review its emergency action plan elements (such as fire, hazardous chemicals, and electrical emergencies) with employees covered by the plan when the employees' responsibilities under the plan changed
29 *CFR* 1910.305(g)(2)(ii)	Serious	Flexible cords in heat tape used to warm chocolate pipes between Buildings 1 and 2 were not spliced or tapped as required by regulation
29 *CFR* 1910.37(b)(2)	Other-than-Serious	No exit sign on a Building 1 basement door as required by regulation that each exit must be clearly visible and marked
29 *CFR* 1904.29(b)(2)	Other-than-Serious	An OSHA 301 incident report form or equivalent was not filled out for each of 10 employee injuries or illnesses entered in the OSHA 300 log or equivalent[1]
29 *CFR* 1904.29(b)(3)	Other-than-Serious	Seven workplace-related deaths and 3 serious workplace-related injuries were not entered on the OSHA 300 log or equivalent within 7 calendar days of receiving information that a recordable injury or illness has occurred
29 *CFR* 1904.40(a)	Other-than-Serious	The OSHA 300 log or equivalent was not provided to an authorized government representative within 4 business hours
29 *CFR* 1910.1001(j)(3)(i)	Other-than-Serious	Palmer did not determine the presence, location, or quantity of asbestos-containing materials or presumed asbestos-containing materials at the worksite or exercise diligence in informing employees about them
29 *CFR* 1910.1200(h)(1)	Other-than-Serious	Palmer failed to train employees and temporary workers on the hazardous chemicals in the workplace including, but not limited to, ethyl alcohol

[1] OSHA 301 incident forms and OSHA 300 logs are the official records of workplace-related injuries or illnesses submitted by an employer.

1.9.2 Pennsylvania Public Utility Commission

After the explosion, safety staff from the PA PUC Bureau of Investigation and Enforcement asked UGI about leaks and work in the West Reading area. The PA PUC staff elevated their presence throughout the West Reading area in the months after the explosion. On April 10, 2023, the PA PUC sent a letter advising UGI to stop any planned work involving joining assets to Aldyl A piping until the company reviewed its standards, procedures, plans, and training related to Aldyl A piping and other “first-generation plastics.” Further, the PA PUC recommended UGI review its public awareness program and its messaging to non-English-speaking populations.

1.9.3 R.M. Palmer

Since the accident, Palmer has completed the following actions:

- Developed a procedure for how employees should respond to a natural gas leak and trained supervisors and management on it. The procedure directs employees to stop work if an odor is detected; determine whether the odor could be dangerous, such as the rotten-egg smell of natural gas; and evacuate immediately if so, or if employees begin to feel unwell. The procedure also notes that the maintenance department now has a portable natural gas detector that may be used to help detect natural gas.
- Installed in all its buildings externally monitored natural gas alarms. The alarm company calls Palmer supervisors when natural gas safety levels are exceeded. According to the new natural gas procedure, supervisors who are notified by the alarm company must evacuate the workers immediately using the Palmer intercom system.
- Developed an annual English- and Spanish-language workplace emergency safety training program for all employees. The training includes odor awareness with a scratch-and-sniff card to familiarize employees with the smell of natural gas.
- Removed the natural gas heaters and gas piping from the basement of the other production buildings and replaced them with electric heaters.

1.9.4 UGI Corporation

Since the accident, UGI has completed the following actions:

- Conducted walking leak surveys in the area of the accident site and mobile leak surveys of all bare steel and plastic mains installed before 1989 in West Reading.[84]

- Reviewed its Aldyl A assets and developed a new database entry for plastic pipe and fittings in its database to allow evaluation of the specific types, vintages, and sources of plastic pipe and fittings historically installed by UGI and its predecessor companies.

- Developed a new procedure to standardize the remediation of Aldyl A tapping tees, which uses electrofusion repair fittings developed specifically for the tees and updated related operational procedures.[85]

- Created retirement guidance for all service tees with added GPS data showing the location of retired service tees.

- Evaluated procedures related to discovery or exposure of unmarked assets.

- Adjusted its IM program, revising procedures to add information collection requirements for plastic pipes when exposed as part of other activities, incorporating data collection and digitization of material failure reporting, and adding a records correction form to the GIS revision and asset data correction process.

- Created an electronic database in which to record information on distribution system risks and threats, along with a program to train SMEs on its use.

[84] (a) In a *walking survey*, a technician walks near or over gas mains and service lines and up to each meter set in the survey area while carrying a handheld leak-detection instrument. (b) *Mobile leak surveys* deploy vehicles (such as cars or aircraft) with mobile data collection equipment to detect elevated methane concentrations.

[85] An *electrofusion repair fitting* is a plastic pipe fitting with a built-in heating element that melts the plastic at the joining interface, creating a weld.

- Requested that GPTC revise its guidance to recommend natural gas distribution system operators replace or remediate Aldyl A tapping tees and Delrin inserts whenever these are encountered in the field.[86]

- Modified its public awareness program, revising current public communications on “what to do if you smell gas” (including a scratch-and-sniff card) and hiring a communications agency to deploy a new natural gas safety campaign for the general public, with expanded Spanish-language communications. UGI also deployed a public awareness pilot program, meeting with facilities managers for 128 of their largest nonresidential customers, and distributing natural gas safety awareness communications kits. UGI reported that the pilot program was well received, and customers often requested more materials.

- Evaluated its public communications to see where it could share information on natural gas alarm availability and implemented a training program for state police and fire investigators.

- Replaced natural gas mains in the immediate vicinity of the accident site and along Penn Avenue from 2nd Avenue to Park Road.

- Identified 34 natural gas customers in its service territory that could be operating below-ground steam systems to determine whether these systems conflicted with UGI assets. UGI found 14 of these customers that required further investigation on whether the systems conflict with UGI assets and should be remediated. UGI is also applying a risk index model to each of the 14 customer locations with potential conflicts between UGI assets and customer-owned, below-ground steam systems. As conflicts are identified, UGI will initiate remediations that will include, if necessary, the relocation of UGI assets, replacement with steel mains or service lines, or both.

- Updated its general installation requirements in the GOM and the Pennsylvania Design One Call cover letter and issued a companywide technical advisory bulletin to continue identifying heat-generating

[86] GPTC voted to approve UGI’s recommendation. See BSR-GPTC-Z380.1-2022-TR-2023-14.pdf (aga.org)

sources and to raise awareness for field employee escalation when these sources are discovered.

- Requested that West Reading Borough and the Western Berks Water Authority replace the water valve box cover at South 2nd Avenue and Penn Avenue with an appropriately marked cover and that they confirm that none of their water valve covers are marked as gas covers.

- Modified its valve inspection program, implementing a geospatial collection system to locate and document valves; updating procedures for valve identification, validation, record keeping, and for when discrepancies are found in the field; and adding marker balls to all excavated valves.

1.10 Pennsylvania Public Utility Commission Party Removal

In accordance with federal regulations, the NTSB designated PA PUC as a party to this investigation based on its oversight of UGI as a natural gas pipeline operator in Pennsylvania and because the PA PUC could provide technical personnel to assist in the investigation, which it did.[87] In June 2023, the NTSB requested that the PA PUC produce its inspection reports of UGI's DIMP for the 5 years before the accident.[88] The PA PUC declined to provide the reports, citing state confidential security information nondisclosure laws. The PA PUC's interpretation of these laws considered the NTSB to be a "member of the public," thus requiring the information to be withheld.

In September 2023, the NTSB revoked the PA PUC's party status for violating NTSB party guidance by not providing the requested inspection reports.[89] Also in September, the NTSB issued a subpoena to the PA PUC to produce the inspection reports. After lengthy legal action, the NTSB obtained the reports from the PA PUC on April 23, 2024, more than 9 months after the investigation identified the need for them.

[87] See 49 *CFR* 831.11.

[88] UGI provided the DIMP reports themselves to the NTSB on April 19, 2024.

[89] A description of the NTSB party system and the guidance provided to parties can be found on the NTSB's website.

2 Analysis

2.1 Introduction

On March 24, 2023, around 4:55 p.m. local time in West Reading, Pennsylvania, natural gas leaked from a crack in a retired Aldyl A service tee with Delrin insert into the basement of Palmer Building 2 and ignited, causing an explosion and fire that killed 7 Palmer employees, injured 10 people, destroyed Building 2, and damaged another Palmer building.

The analysis will discuss the following safety issues:

- Degradation of a retired Aldyl A service tee that was accelerated by elevated ground temperatures from a corroded and cracked steam pipe nearby.
- UGI's insufficient consideration of pipeline integrity threats, particularly Aldyl A service tees with Delrin inserts at elevated temperatures.
- Presence of unmarked and unreported private assets crossing public rights-of-way, excluding them from PA One Call and increasing the risk of damage to them.
- Delayed evacuation of Palmer's Building 2 despite detection of natural gas by employees and others.
- Natural gas safety messaging from pipeline operator public awareness programs that may not reach certain members of the public.
- Insufficient guidance on natural gas emergency procedures.
- Absence of natural gas alarms in commercial buildings.
- Insufficient accessibility of gas distribution line valves.

The NTSB's review of the circumstances that led to this accident found the following areas either were not factors in or were not causal to the accident:

- *Pipeline overpressurization*. The pressure at the Cherry Street main at the time of the accident was about 53 psig, lower than the system's maximum allowable operating pressure of 60 psig.
- *Local emergency responder actions*. The response of the fire departments and law enforcement agencies was timely and appropriate. Emergency response personnel were on the scene even

before the first 9-1-1 call, and there was no indication that the response exacerbated any injuries.

Therefore, the NTSB concludes that neither of the following issues were causal to the accident: (1) pipeline overpressurization or (2) local emergency responder actions.

2.2 The Accident

About 4:55 p.m. on March 24, a natural gas–fueled explosion and fire destroyed Palmer's Building 2, killed 7 people, and injured 10 others. The explosion damaged Building 1 to the south of Building 2 and an apartment building to the north, displacing 3 families.

At least 13 minutes before the explosion, multiple Palmer employees reported smelling a gas odor in both Buildings 1 and 2.[90] The smell was strong enough to cause some employees to leave the buildings. Many other employees—including several who were killed in the explosion—were in the buildings when the explosion occurred. Some surviving employees indicated they did not know what to do about the odor, and others stated they had remained in the buildings because they were concerned that evacuation would count against their workplace attendance. Three of the victims entered Building 2 just before the explosion in an apparent attempt to find the source of the gas odor. All seven people killed in the accident were inside Building 2 at the time of the explosion.

Local and state emergency services arrived on the scene just after the accident to begin firefighting and rescue operations. Flash fires were observed above and around the firefighters as they moved about the accident site, and firefighters recalled a gas-fed fire in the basement of Building 1 coming through a chocolate pipe conduit between the two buildings, indicating gas was still burning after the initial explosion. About 5:00 p.m., the City of Reading Fire Department contacted UGI, and UGI first responders subsequently isolated the gas system around 6:15 p.m. The fires were extinguished soon after.

2.2.1 Source of Natural Gas that Fueled the Explosion

An investigation conducted by local, state, and federal law enforcement determined that the explosion and fire originated in the southwest quadrant of the

[90] A Palmer employee recalled smelling gas near the boiler room behind Building 1 the day before the accident, but the investigation did not determine that this was related to the leak at Building 2.

Building 2 basement, where natural gas had accumulated until it reached an explosive concentration and ignited, and that the ignition source was unknown.

Bar hole tests conducted 6 days after the accident showed underground gas concentrations near the Cherry Street and South 2nd Avenue intersection, which, at the time, was the closest accessible area to the explosion site. The tests indicated that gas had leaked from the distribution system on Cherry Street and spread underground. When a leak source is below ground, paved surfaces like roads or walkways inhibit natural gas from venting, resulting in further migration underground and through paths like cracks or holes. Further bar hole tests conducted on April 22, about a month after the accident, showed residual gas underground near the Building 2 service line.[91] The bar hole tests showed that enough gas had been present underground at the time of the accident to still cause residual gas measurements a month later.

A law enforcement investigation report indicated that natural gas had entered the basement of Building 2 in the area where the chocolate conduits entered the basement, as well as through a crack in the building foundation and a location where an unused gas pipe entered the building.

Postaccident visual examinations of the chocolate pipe conduits revealed an unobstructed pathway for airflow between Palmer Buildings 1 and 2. To determine whether natural gas could flow between the buildings, the NTSB observed as a deputy fire marshal placed a smoke generator in the basement of Building 2. NTSB investigators saw the smoke emanating from the ground next to the Building 2 basement, close to the service line, indicating a path between the basement of Building 2 and the ground surrounding the gas distribution system. The NTSB saw smoke exiting the conduits in the basement of Building 1, confirming the ability of gas to flow from the Building 2 basement to the Building 1 basement through the conduits. The NTSB also found smoke on the third floor of Building 1. This observation was consistent with employee reports of a gas odor in various areas of Building 1 before the accident. These examinations and tests indicated that natural gas had been escaping from UGI’s gas distribution system in the vicinity of Cherry Street into the ground and from there migrating to the Building 2 basement, through the chocolate pipe conduits, and to Building 1.

To determine the point of natural gas release from the distribution system, the NTSB conducted incremental pressure testing and excavations. With these tests the NTSB identified three leaks coming from the gas distribution system near the

[91] Between the March and April bar hole tests, some of the gas had vented through previous bar holes, cracks, and open areas in the pavement.

southwest quadrant of Building 2.[92] The largest leak was at the Building 2 service tee that had been retired in 1982 and capped off but was still connected to the natural gas distribution system at full gas system pressure, as was UGI standard and common industry practice. The NTSB Materials Laboratory examination of the tee revealed that it was fractured through its tower from the top to nearly the bottom, forming a 1.9-inch crack that was open at one end. The insert was completely fractured near the bottom, and its upper portion and cap were not present, providing an open path for gas to escape. Slow crack growth features of the fracture, discussed below, indicated that the crack had been present before the explosion. Therefore, the NTSB concludes that natural gas migrated from the Aldyl A retired service tee through the ground then into the Palmer Building 2 basement, chocolate pipe conduits, and Building 1, and fueled the explosion in the Building 2 basement.

Further examination of the longitudinal fracture in the tower shell of the retired service tee to Building 2 revealed that it was flat and featureless with fibrils, transitioning to hackle near the base of the tower, which is indicative of slow crack growth. The retired service tee's Delrin insert had a through-wall fracture that showed crazing on the side closest to the steam pipe and porous and granular features elsewhere. The outer surface of the Delrin insert showed surface cracking and volume loss, indicative of decomposition.

The main factors driving slow crack growth are stress, temperature, and material susceptibility. Polyethylene pipe specifications provide limits on pipe operations and operating environments that include the temperature of the operating environment. Operating outside of these environments can accelerate the rate of defect growth. The specifications for Aldyl A piping systems, which included service tees with Delrin inserts, indicated a maximum ground temperature of 100°F. The slow crack growth in the Aldyl A tower shell and the thermal decomposition of the Delrin insert were consistent with exposure to elevated temperatures, although the investigation could not determine the exact ground temperatures surrounding the Building 2 service tee before the accident. The susceptibility of certain Aldyl A polyethylene resins to slow crack growth has been documented extensively and is discussed below (Palermo 2011, Haine 2014). Because the growth rate of such cracks increases exponentially with temperature, small increases in temperature can lead to comparatively large changes in crack growth rate.

[92] A small leak in the active polyethylene service line to Building 2 exhibited a cut in the line that the NTSB determined was consistent with damage from the explosion. Another leak was identified in the NTSB Materials Laboratory on the Aldyl A gas main underneath the 2021 replacement service tee; having a measured flow rate of 0.6 standard cubic feet per hour, the NTSB determined this leak was very small and did not contribute to the accident.

Published data indicate that Delrin polyacetal will start to show signs of aging with time and that higher temperatures accelerate the onset of aging effects (Delrin 2024).[93] However, the service tee at Building 1 also contained a Delrin insert from 1982 but did not exhibit any of the material degradation of the retired Building 2 tee insert. Although the 40-year-old Delrin Building 2 service tee insert might have aged in any thermal environment, its extensive material degradation (particularly when compared to the Building 1 service tee insert, which had been installed at the same time) indicates that, as with the Aldyl A tower shell, the temperature in the surrounding environment had been significantly elevated for enough time to facilitate the degradation. Thus, the service tee and the Delrin insert were likely exposed to elevated temperatures for a sustained period of time, which led to slow crack growth and thermal decomposition, respectively, that allowed natural gas to be released from the gas distribution system. The NTSB concludes that the 1982 retired service tee leaked because of degradation caused by exposure to elevated temperatures; more specifically, slow crack growth of the Aldyl A tower shell and thermal decomposition of the Delrin insert.

Running perpendicular to the Cherry Street natural gas main, about 2 feet to the west of the retired tee and about 15 inches above it, was a steam pipe owned by Palmer.[94] The pipe was part of a steam heating system used seasonally to provide heat to parts of Building 2. When the NTSB excavated the section of Cherry Street that contained the natural gas main and Building 2 service tees, a section of the Palmer steam pipe was found heavily corroded, with a 4-inch through-wall crack. The NTSB further examined the cracked segment of the steam pipe and determined the wall had been corroded to less than 20% of its original thickness in the vicinity of the crack. The corrosion-induced wall loss on the pipe would have significantly reduced the force needed to cause it to crack. The location of the crack indicated that, at some point before the accident, an external load had been applied to the steam pipe that exceeded its shear strength where the pipe wall had been thinned extensively by corrosion, causing the pipe to shear locally and the crack to form.

Finite element simulations conducted by the NTSB Materials Laboratory found that in the most probable scenarios, the heat from an intact steam pipe could only increase the ground temperature near the retired tee by about 27°F to 40°F above

[93] For example, samples of select grades of Delrin stored at 135°F to 140°F showed a notable loss of tensile strength after about 7 years. The same types of samples stored at room temperature retained their strength after 20 years.

[94] This steam pipe was about 25 to 30 feet from the Building 1 service tee.

the baseline ground temperature. In other words, without the crack, the steam pipe had limited capacity to increase the temperature of its surroundings.

As noted above, the NTSB found a small crack in the Cherry Street gas main underneath the active service tee to Building 2. The 0.39-inch crack in the gas main, which was also made of Aldyl A, was too small to have contributed to the accident, but it also exhibited features consistent with progressive slow crack growth that further indicated a significantly elevated temperature environment. The crack surfaces exhibited start–stop features consistent with thermal expansion and contraction of the service tee saddle and undersaddle, also known as thermal stress cycling, likely due to fluctuations in ground temperature as high-temperature steam flowed periodically through the pipe based on heating demand in Building 2 and escaped through the steam pipe crack.[95]

The NTSB also examined a collapsed plastic marker ball, first installed in 2021, that had been recovered from the accident site and determined that the ball's seam had ruptured in a manner consistent with a buildup of internal pressure inside the ball caused by an elevated temperature environment. The same thermal fluctuations in the ground temperature that caused thermal stress cycling in the Cherry Street gas main subsequently collapsed the ball inward. Collapsed marker balls are rarely, if ever, encountered in routine utility work, indicating that seasonal changes in ground temperature likely did not contribute to the state of the marker ball. The high temperatures needed to degrade the retired service tee, initiate slow crack growth in the Cherry Street gas main, and rupture the marker ball seam were consistent with direct release of steam into the ground surrounding the steam pipe and retired service tee.[96] Therefore, the NTSB concludes that steam escaping through the crack of the corroded steam pipe significantly elevated the ground temperature at the location of the retired service tee, which accelerated its degradation and ultimately led to its failure.

[95] The NTSB considered whether the heat tape that had been affixed to the outside of the chocolate pipes could have caused elevated ground temperatures and determined it could not have raised the ground temperature enough to cause the degradation of the retired service tee. The pipes were situated inside a larger pipe conduit, and the air inside the conduit likely prevented direct heat transfer to the ground.

[96] Further, had the retired service tee displayed the level of degradation in 2021 that was visible upon postaccident excavation, the UGI crew would not have been able to complete the tee replacement project, which required them to install a threaded service tee cap and conduct a soap test to make sure the tee was free of leaks.

The NTSB reviewed an image of the UGI crew taken by Palmer during the 2021 service line replacement project. The image showed that UGI had been excavating with mechanized equipment around the same location as the crack in the steam pipe. Further, a UGI crewmember stated in an interview with the NTSB that a subsurface white powder, later determined to be calcium carbonate, had been visible during the 2021 excavation. The NTSB did not determine the purpose of the powder, but it further indicated the proximity of the UGI work to the steam pipe itself, as the powder was visible both in the Palmer photograph and when the NTSB excavated a section of Cherry Street after the accident. A review of PA One Call records did not show any other excavation projects in this area since 2021. The shearing of the pipe is consistent with loss of soil support that left the steam pipe vulnerable to shear and failure given the localized corrosion.[97] However, it could not be determined what specific event or events caused the pipe's ultimate failure. Further, evidence recovered from the scene did not indicate why more extensive corrosion had occurred where the pipe failed.

In an interview with the NTSB, a truck driver who made daily deliveries of chocolate to Palmer's West Reading facilities recalled that, at some point after the UGI service tee replacement and gas meter relocation project on February 16, 2021, he would occasionally see steam rising from the section of asphalt pavement that UGI had replaced during the project. He did not recall seeing the steam before the project. This recollection is consistent with the steam pipe cracking and beginning to release steam and heat into the ground sometime between the UGI service tee replacement project and the accident.

Palmer management was aware of UGI's meter relocation project and, according to recollections from a UGI crewmember, of the location of the steam pipe as well. Palmer records indicated that the steam heating system boiler unit was inspected annually by one of their maintenance contractors and checked daily by Palmer mechanics; however, Palmer did not have maintenance records on the steam pipe itself. The extensive corrosion found on the steam pipe in the area of the crack further indicated the pipe had not been maintained. Therefore, the NTSB concludes that Palmer's lack of awareness of corrosion-induced wall loss on the steam pipe from Building 1 to Building 2 left the steam pipe vulnerable to localized shear and cracking when external loads changed, which led to steam heating the ground near the retired service tee after UGI's 2021 service tee replacement project.

[97] External corrosion was observed along the entire length of the steam pipe when it was exposed after the accident. Although the remaining wall thickness was measured at some locations, the detailed evaluation focused on the portion that contained the through-wall crack. This section was sent to the NTSB Materials Laboratory.

2.2.2 Delayed Evacuation

At Palmer's facilities in West Reading, natural gas was used for the Building 2 basement heating system, the boiler for the steam heat system, and a backup generator. In interviews with the NTSB, Palmer management characterized the risk associated with a natural gas leak as "low" because they had few natural gas–fired appliances at that location. The perception was that the possibility of any natural gas leak would therefore be relatively minimal. The company's emergency plan manual, the Red Book, listed UGI's emergency number and contained floor plans with utility shut-off locations but lacked a procedure for when to use the number or how to shut off the gas. The company's crisis management plan listed various potential threats to business operations but did not include a natural gas emergency in this list. Likewise, the Red Book contained procedures on how to respond to some of these threats but not to natural gas. Palmer did not provide employee training on natural gas hazards and how to respond to the smell of gas.

The flammable and explosive hazards of natural gas have long been recognized by the pipeline industry. To reduce the chances that natural gas leaks will go undetected, federal regulations require the addition of an odorant to natural gas distribution pipelines. General best practices for when natural gas is detected are to immediately evacuate to a safe distance and then call either the gas operator or 9-1-1. For example, UGI's website instructs anyone smelling a gas odor to "act fast" and leave the area and call UGI, 9-1-1, or both.

Employees working in both Buildings 1 and 2—and some outside of the buildings—recalled smelling gas or a strange odor on the afternoon of March 24, 2023. In interviews with the NTSB, many Palmer employees stated that they knew that the distinctive sulfurous odor indicated natural gas, but others recalled expressing initial confusion as to what the smell was. Some employees asked their supervisors for guidance but were not told to evacuate; one employee in Building 1 and another in Building 2 self-evacuated. Witness accounts and surveillance camera data indicated that many employees in Building 2 at the time of the accident had been aware of the gas smell at least 13 minutes before the explosion. None of the employees that were aware of the natural gas odor pulled the fire alarm when it was detected, and Palmer management did not issue an evacuation order.

Palmer's CEO told the NTSB that employees were empowered to evacuate for safety reasons. But some employees interviewed after the accident stated that they did not evacuate Building 1 even after smelling gas because they were concerned it would count against their workplace attendance. A survivor of the explosion, who was in Building 2 when it exploded and had smelled gas there, told the NTSB that she thought employees were supposed to wait for instructions from their supervisor in such a situation. Surveillance camera data and interviews with other Palmer employees indicated that the lead mechanic, human resources director, and plant manager were in the process of investigating the leak at the time of the explosion, in which all three were fatally injured. Without a natural gas emergency evacuation procedure, Palmer management and employees were not offered a clear understanding of the critical danger of a natural gas leak; even Palmer management did not know to immediately evacuate the building in case of a natural gas odor.

The Red Book contained an orderly evacuation procedure for general emergencies that Palmer employees were trained on as part of regularly conducted fire drills. Fire alarms, triggered manually or by automatically operated smoke or fire detectors, indicated to employees that they should evacuate. The NTSB reviewed company records of past fire drills and evacuations and found that an orderly evacuation could take place in under 5 minutes.

Further, had someone pulled the fire alarm once the odor was reported in Building 2 (13 minutes before the explosion), it is likely that employees could have evacuated with enough time to reach a safe distance from the eventual explosion. Therefore, the NTSB concludes that had Palmer implemented natural gas emergency procedures and trained their employees and managers on them before the accident, the employees and managers could have understood the danger they faced and could have responded by immediately evacuating and moving to a safe location away from both buildings. Since the accident, Palmer has installed natural gas alarms in all their buildings, developed an annual workplace safety training program in both English and Spanish, replaced natural gas heaters in all their buildings with electric heaters, and developed an emergency procedure for how to respond to a natural gas leak.

Palmer's new procedure tells employees to determine whether an odor could be dangerous before deciding to evacuate and notes that portable natural gas detectors are available to help detect natural gas. The NTSB is concerned that by telling employees to judge whether an odor is dangerous—and by noting the availability of portable natural gas detectors—the new procedure could lead to employees investigating natural gas odors rather than immediately evacuating to a safe location. Three of the employees fatally injured in this accident were investigating the gas odor at the time of the explosion instead of evacuating. Therefore, the NTSB recommends that Palmer revise its natural gas emergency procedure to direct all employees to immediately evacuate upon smelling natural gas odorant and to specify a safe evacuation location.

2.3 Insufficient Consideration of Known Threats from Plastic Piping

The vulnerability to slow crack growth, also called brittle-like cracking, of early vintage Aldyl A and other early vintage polyethylene piping materials under certain environmental (such as high ground temperatures), installation, and service conditions has been extensively documented.[98] In 1998, the NTSB issued a special investigation report, *Brittle-Like Cracking in Plastic Pipe for Gas Service*, which concluded that the procedure used in the United States to rate the strength of plastic pipe may have overrated the strength and resistance to brittle-like cracking of much of the plastic pipe manufactured and used for gas service from the 1960s through the early 1980s. The report found that much of this early vintage plastic piping may therefore be susceptible to premature brittle-like cracking failures when subjected to stress intensification (NTSB 1998). In response, PHMSA and its predecessor, the Research and Special Programs Administration, issued four advisory bulletins addressing brittle-like cracking in plastic pipe materials.

The 2002 bulletin *Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe* warned that "brittle-like cracking (also known as slow crack growth) can substantially reduce the service life of polyethylene piping systems" (Research and Special Programs Administration 2002). The bulletin specifically cited certain Aldyl A piping material manufactured by DuPont Company before 1973—the same material as the retired Building 2 service tee—as potentially susceptible to brittle-like cracking.[99] A 2007 update to the advisory bulletin added Delrin-insert tapping tees to the list of polyethylene pipe materials susceptible to brittle-like cracking.

District heating systems that use underground steam pipes like the one used by Palmer can be found throughout the United States, particularly in large cities like New York; San Francisco, California; Philadelphia, Pennsylvania; and Denver, Colorado. Of the 68 district heating systems still operating, just over half were built before 1950—with one-quarter built before 1900 (Pierce 2022). The extent of district heating systems nationwide means that other natural gas pipeline operators may have assets near steam pipes. Research has established that elevated temperatures can affect the pressure rating of polyethylene plastic piping, with one study citing the

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[98] These conditions, outlined in a 2002 PHMSA advisory bulletin, include rock impingement, shear and bending stresses from such factors as nearby excavation or frost heave, damaging squeeze-off practices, and installation in areas with higher ground temperatures.

[99] In the 1970s, DuPont found that some Aldyl A pipe samples made between 1970 and 1972 had low-ductile inner wall characteristics resulting from excessive temperature settings during the extrusion process (Haine 2014).

adverse effects of district heating systems on polyethylene gas pipelines (Akhmerova and others 2021).

Early vintage Aldyl A piping is limited to operating conditions below 100°F, and operating outside these conditions increases the risk of slow crack growth. For plastic piping in general, the risk of damage grows as temperatures increase above typical ground temperatures. Modern plastics (including later vintages of Aldyl A) are more resistant to damage at higher temperatures than earlier vintages. Operators base the maximum operating pressure for plastic piping on the properties of the pipe and an assumed maximum environmental temperature; as seen in this accident, the release of steam can raise that temperature, creating an environment in which the piping was not originally designed to operate. To address the risks associated with plastic piping, pipeline operators must be aware of where these assets are located in their system and which ones may be susceptible to slow crack growth or other degradation from outside factors, such as heat. Before the accident, UGI had evaluated the threat and consequences of early vintage Aldyl A to be the same as other polyethylene fittings in its risk models, counter to PHSMA guidance. UGI was not able to conduct a complete inventory of its plastic assets, including manufacturer, with available records. The Palmer steam pipe had not been recorded or identified in UGI’s records, precluding UGI from identifying the elevated temperature environment as a threat. The NTSB concludes that because UGI did not have sufficient threat information available for analysis in its DIMP, it could not effectively evaluate and address the risk to pipeline integrity of its plastic piping in elevated temperature environments.

UGI strengthened its data collection and record correction procedures and is working to remediate Aldyl A service tees with Delrin inserts as they are discovered in the field, using new operational procedures and electrofusion repair fittings developed specifically for the tees. UGI is also conducting a complete analysis of all its assets that may be exposed to elevated temperature environments to evaluate and address this threat to pipeline integrity, but this effort needs to be completed. Therefore, the NTSB recommends that UGI inventory all its plastic natural gas assets that may be located in elevated temperature environments and address the risk associated with these assets.

The NTSB is concerned that the extent of the use of plastic natural gas assets throughout the country, including Aldyl A, and their susceptibility to degradation in elevated temperature environments raise the risk of an accident like this one. This accident demonstrates the need to quantify the extent of plastic piping assets in natural gas pipeline systems that are at risk of exposure to elevated temperatures. Historical asset records on pipe installed more than 40 years ago may not be accurate, possibly complicating operators' efforts to assess the extent of plastic piping throughout their systems, as UGI experienced. A 2014 study of natural gas pipeline operators in California demonstrated uncertainty similar to UGI's regarding the extent of the operators' Aldyl A assets (Haine 2014). The NTSB concludes that given the widespread adoption of plastic piping, including Aldyl A assets, and the unreliability of historical asset records, operators may not be aware of the locations of their plastic natural gas assets that are vulnerable to degradation in elevated temperature environments, thus appropriate mitigations may not be in place.

Specific guidance from PHMSA on identifying and evaluating the risks associated with plastic piping in elevated temperature environments would reduce the chances of a similar accident occurring in the future. Once pipeline operators have identified the extent of the threat in their systems, they can evaluate risks and implement mitigations where necessary. Therefore, the NTSB recommends that PHMSA issue an advisory bulletin to all regulated natural gas distribution pipeline operators referencing DIMP regulations and encouraging operators to:

- Complete a one-time inventory of all plastic assets that are located in environments that experience or are at risk of elevated temperatures;
- Continue, during maintenance and new construction projects, to identify plastic assets that are in elevated temperature environments; and
- Evaluate and mitigate risks to deter the degradation of these assets.

Although the failure of Aldyl A tees with Delrin inserts is well documented, this is the first accident NTSB has investigated in which thermal degradation of an Aldyl A service tee with Delrin insert resulted in a fracture that released a substantial amount of natural gas and led to an explosion. Less-severe Delrin insert and cap failures have been documented: 2 years after the 2007 PHMSA advisory bulletin, a 2009 Gas Technology Institute report detailed several insert and cap failures in Aldyl A service tees with Delrin inserts (Mamoun, Maupin, and Miller 2009). Further, data reported to the Plastic Pipe Database Committee show that about 20% of failures of Aldyl A fittings manufactured by DuPont and Uponor were likely caused by the tee with the Delrin insert (American Gas Association 2024).

The NTSB acknowledges that most documented cases of insert and cap failures in Aldyl A service tees have resulted in low-volume leaks; however, we believe that these data must be reassessed in light of this accident. Thus, the NTSB concludes that the severity of this accident, combined with the documented history of failure of Aldyl A service tees with Delrin inserts, indicates a risk associated with the continued use of these components.

Although the 2007 PHMSA advisory bulletin noted that Delrin-insert tapping tees were susceptible to slow crack growth, the NTSB believes that operators need to be alerted to the potentially severe consequences of the tees' degradation. The NTSB therefore recommends that PHMSA issue an advisory bulletin that reviews the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, and advises all regulated natural gas distribution pipeline operators to address the risk associated with Aldyl A service tees with Delrin inserts, including replacing or remediating them.

As part of its IM program, before the accident UGI had reviewed records of leaks and failures associated with Aldyl A service tees with Delrin inserts. They concluded that the tees had a history of leakage from the black Delrin caps and noted that these leaks had been found through normal operations and did not result in serious consequences. However, the vulnerability of early vintage Aldyl A materials to slow crack growth indicate that the Delrin caps were not the only material failure risk that UGI's IM program should have considered. Even though a UGI crewmember recalled a Palmer employee telling them about the presence of Palmer's steam pipe in 2021, UGI had neither trained nor instructed field personnel to report unknown private pipelines to its IM program for evaluation as a pipeline integrity threat. The pipe was not exposed and was not documented in UGI records, preventing UGI's IM program from evaluating the potential threat of the steam pipe. The NTSB concludes, therefore, that had UGI developed procedures and training for its field crews to report potential sources of elevated temperatures (such as steam pipes) found in the vicinity of natural gas assets, the threat posed by the steam pipe could have been identified and assessed through UGI's DIMP, and mitigative measures could have been implemented.

Underground steam pipelines are not the only subsurface assets that pose a threat to natural gas systems and to plastic pipes and fittings in general. A 2007 study cited underground high-voltage electric cables as a source of elevated ground temperatures (Palermo, Zhou, and Farnum 2007). The NTSB previously investigated an accident in South Riding, Virginia, in which heat generated by a damaged electrical line caused the natural gas service line to soften, weaken, and leak, allowing gas to migrate into a home, where it ignited and exploded (NTSB 2001). The NTSB is currently investigating a natural gas explosion that destroyed a home and killed two people in Bel Air, Maryland, in August 2024.[100] The preliminary report for the investigation states that the home's plastic gas service line had been installed in a

[100] The preliminary report for this ongoing investigation can be found on its web page (investigation number PLD24LR006).

common trench with the home's electrical cables and was found with a hole on the bottom of the pipe, and the home had experienced an electrical power outage just before the explosion.

The GPTC Guide states that natural gas pipeline operators should consider heat sources as a hazard to plastic gas main and service lines during construction and offers information on evaluating plastic gas main and service line installations near heat sources for possible mitigative measures. In its DIMP guide material, the referenced GPTC Guide does not mention effects on plastic pipes placed near steam lines or otherwise exposed to potentially elevated temperatures. When a hazard is identified, a pipeline operator must collect information and provide the information to its IM program for evaluation, which did not happen when UGI's field crew encountered the steam pipe near its natural gas assets buried under Cherry Street. The NTSB concludes that additional industry guidance highlighting the threat to pipeline integrity of plastic pipeline exposure to elevated temperatures could improve awareness of this threat so that other operators may identify and effectively manage it through their DIMPs. The NTSB therefore recommends that the GPTC develop guidance for natural gas pipeline operators to ensure that their DIMPs appropriately assess and address threats to plastic pipelines posed by nearby assets that may elevate the temperature of the environment near the pipeline.

After the accident, UGI identified which of its customers may have steam systems located near natural gas assets and is analyzing these areas to determine mitigation measures. UGI updated its procedures to augment surveillance and documentation of steam pipelines in field maps and reporting of such assets to engineering staff. UGI also revised its design manual for determining the route of new or replacement gas assets and for considering separation standards for utilities that present a high safety risk, including steam and electric lines.

This accident, and others investigated by the NTSB, highlight the importance of natural gas pipeline operators strengthening their DIMP programs to more effectively address pipeline safety risks before they result in a catastrophic accident. Our investigation of a 2018 natural gas–fueled explosion at a residence in Dallas, Texas, found that the natural gas pipeline operator had neither adequately considered nor mitigated against threats degrading its pipeline system, the likelihood of failure associated with these threats, or the potential consequences of such a failure in its IM program (NTSB 2021). Therefore, the NTSB recommended that PHMSA

> evaluate industry's implementation of the gas distribution pipeline integrity management requirements and develop updated guidance for improving their effectiveness. The evaluation should specifically

> consider factors that may 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. (P-21-2)[101]

Of note, in 2023, PHMSA issued a notice of proposed rulemaking (NPRM) that, among other things, would require operators to identify and minimize the risks to their systems from specific threats in their DIMP plans (for example, the presence of certain materials, age, overpressurization of low-pressure systems, and extreme weather and other geohazards).[102] The NTSB supported the NPRM. As of the date of this report, PHMSA is still developing the guidance language for improving the effectiveness of pipeline IM program requirements. The final rule will need to be reviewed to determine if NTSB Safety Recommendation P-21-2 has been satisfied. A final rule is scheduled to be published in 2025.[103]

UGI had developed a DIMP, which was reviewed yearly by the PA PUC. However, as stated earlier, UGI's DIMP had not identified the need to address the threat posed by subsurface assets. The NTSB thus concludes that by not addressing the threat posed by the steam pipe, UGI's DIMP was not effective in preventing the accident. Thus, the current accident again illustrates the importance of strengthening DIMP requirements throughout the natural gas pipeline industry. Therefore, the NTSB reiterates Safety Recommendation P-21-2 to PHMSA.

2.4 Unmarked Private Assets in Public Rights-of-Way

Pennsylvania's Underground Utility Line Protection Law requires owners and operators of underground lines serving one or more customers to register with PA

[101] Safety Recommendation P-21-2 is currently classified Open—Acceptable Response.

[102] The NPRM, "Pipeline Safety: Gas Pipeline Leak Detection and Repair," can be found at https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair. In August 2024, API released RP 1187, "Pipeline Integrity Management of Landslide Hazards."

[103] The unified agenda for this rulemaking can be found at https://www.regulations.gov/docket/PHMSA-2021-0039/unified-agenda.

One Call (PA One Call 2024).[104] Based on the definitions within Amended Pennsylvania Act 287, the Underground Utility Line Protection Law, Pennsylvania did not require Palmer to be a member of PA One Call.

The Common Ground Alliance's (CGA) *Best Practices Guide* contains a uniform pavement marking color code, which Pennsylvania used. The code includes steam pipelines along with other potentially dangerous materials transported by pipeline such as gas, oil, petroleum, or gaseous materials. The guide recommends marking the location of underground steam pipes with yellow pavement paint. The CGA guide further explains in Best Practice 3-32 that owners and operators of private assets who are not members of an 811 center like PA One Call will not be notified of a planned excavation, and the center will not locate their assets.

Had Palmer's privately owned steam pipelines been registered with PA One Call, these assets would have been identified and marked with a uniform pavement marking as recommended by CGA. Pavement markings indicating the location of Palmer's steam pipelines as well as UGI assets would have been the best practice to alert anyone excavating near the steam pipe of its presence before they began digging.

Palmer's condensate pipe, chocolate pipes, and steam pipe underneath Cherry Street crossed a public right-of-way.[105] Public rights-of-way are subject to excavation not only for utility work, but also for building construction and road work. The entities that perform this work can include utility companies, private contractors, and homeowners. The NTSB concludes that the omission from PA One Call of certain assets transporting high-temperature materials like steam that are located in a public right-of-way can pose a risk to anyone excavating in the vicinity. Damage to these unmarked assets can also damage and degrade nearby assets. Therefore, the NTSB recommends that the Commonwealth of Pennsylvania modify its Underground Utility Line Protection Law to require all owners and operators of pipelines transporting

[104] The law, Title 73 P.S. Section 176 et. Seq., defines as a "line" or "facility" "underground conductor or underground pipe or structure used in providing electric or communication service, or an underground pipe used in carrying, gathering, transporting, or providing natural or artificial gas, petroleum, propane, oil, or petroleum and production products, sewage, or water or other service to one or more transportation carriers, consumers, or customers thereto." The definition of "line" or "facility" further includes "unexposed storm drainage and traffic loops that are not clearly visible" and "oil and gas well production and gathering lines." The term "facility owner" does not include, among other listed things, a person serving the person's own property through the person's own line, if the person does not provide service to any other customer.

[105] The steam pipe and Palmer's other pipes are no longer in use after the explosion.

steam or other high-temperature materials located in public rights-of-way to register their assets with PA One Call.

The best practices presented in CGA's Best Practice Guide contain both practice statements and practice descriptions, which together provide greater detail to assist with implementation of the practices. Best Practice 3-26 offers clear guidance on who should be members of an 811 center: an entity transporting products or services for consumption or use by means of an underground facility, or for its own use by means of an underground facility in or crossing a right-of-way or utility easement. Although the guidance is clear, the NTSB is concerned that states other than Pennsylvania may also lack requirements for pipelines transporting steam to register with their 811 centers. With stakeholder groups encompassing excavators, gas distribution and transmission companies, state regulators, and more, CGA is well-positioned to conduct outreach on its best practices for 811 center membership. Thus, the NTSB concludes that broad nationwide adoption of CGA's recommended Best Practice 3-26 on 811 center membership can help prevent accidents similar to this one by increasing awareness of underground private assets, like some steam pipes, that cross public rights-of-way. Therefore, the NTSB recommends that CGA identify and pursue opportunities for improving adoption of its best practices on 811 center membership, including updating its best practices guide and encouraging states to adopt the updated guidelines.

2.5 Public Awareness and Preparedness

Education and awareness about natural gas are critical to help organizations understand the risk to their facilities and employees and to motivate them to implement policies, procedures, and training to mitigate risks associated with natural gas hazards. For this reason, federal regulations adopted by state pipeline regulators require natural gas pipeline operators to comply with public awareness program standards outlined in API RP 1162, the first edition of which was released in 2003 and is incorporated by reference into the regulations. API RP 1162 is now in its third edition. One of the objectives of such programs is to educate the affected public on how to recognize and respond to a pipeline emergency. As described in the first edition of API RP 1162, the affected public includes people living in single- and multifamily residences as well as "places of congregation" such as businesses or schools with natural gas service.

API RP 1162's baseline communication requirement for the affected public is twice-annual bill stuffers, and these were part of UGI's public awareness program. However, business mail that includes the gas bill and stuffers often is directed to a dedicated department at an organization (such as accounting) and not always seen by all employees. UGI also communicated safety messages through other channels, such as television, radio, newspaper, and social media, as well as community events like baseball games. Like bill stuffers, most of these are one-way communications from UGI with no guarantee that their customers received the information or paid attention to it.

The NTSB has investigated accidents in which ineffective aspects of operators' public awareness programs have led to a lack of public understanding of natural gas hazards. In 2013, we investigated the explosion of a public housing apartment in Birmingham, Alabama, when natural gas in the apartment ignited (NTSB 2016). We found that residents had smelled gas as far back as 2 weeks before the explosion but had not informed the gas company or local authorities; after the accident, the pipeline operator bolstered its dissemination of natural gas safety information to its customers. In our investigation of a 2014 apartment building explosion in New York City, we found that the operator's public awareness programs "did not effectively inform customers and the public about both the importance of reporting a gas odor and the number to call to report a gas odor" (NTSB 2015). The NTSB's investigation of a 2010 natural gas transmission pipeline rupture in San Bruno, California, found that the Pacific Gas and Electric utility company had not corrected a deficient public awareness program that had left the affected public alarmingly unaware of pipeline safety or even pipeline proximity (NTSB 2011).

In interviews with the NTSB after the accident, Palmer management could not recall receiving natural gas safety information from UGI through any means, and they told the NTSB that they believed that their West Reading facilities were at low risk for a natural gas explosion and that employees would have time to react to a leak. Palmer management based this assessment on the minimal natural gas usage in Buildings 1 and 2. However, as demonstrated in this accident and others, any gas leak is dangerous, no matter how minimal the gas usage may be. The underestimation of the danger associated with natural gas leaks indicates that Palmer management had not been adequately informed about these risks.

Effectiveness data on UGI's public awareness program gathered before the accident showed that about one-third of respondents described themselves as either "not too informed" or "not at all informed" about pipelines in their community; a separate survey indicated only about one-third of the affected public who responded had read some or all of UGI's natural gas safety brochure. The data on UGI's public awareness program effectiveness, along with Palmer's deficient understanding of the risks associated with natural gas leaks, indicate room for improvement. The NTSB is concerned that the communications sent by natural gas pipeline operators to their customers in businesses or places of congregation do not adequately inform those who do not directly receive gas bills of natural gas safety. The NTSB thus concludes that natural gas pipeline operator public awareness programs may not reach members of the public in places of congregation or in multifamily residential buildings who do not directly receive bill stuffers; thus, these members of the public may be unaware of the natural gas safety guidance to immediately report a natural gas odor.

After the accident, UGI modified its public awareness program, revising its public communications on “what to do if you smell gas” and developing a new natural gas safety campaign with expanded Spanish-language communications. UGI also has implemented a public awareness pilot program, meeting with and distributing natural gas safety awareness communications kits to their commercial and industrial customers. UGI reported that the additional outreach was well received and that many customers requested additional kits. The NTSB remains concerned that other natural gas distribution pipeline operators may have the same communications issues that UGI previously had with businesses such as Palmer. Effective safety communications are techniques that have proven to be successful in engaging relevant populations—that is, people who live, work, or congregate within the coverage area of a pipeline system—and in ensuring that these audiences receive and understand the safety message. The customer engagement with UGI’s postaccident public awareness pilot program indicates effective safety communication with its customers and that operators have ample room and ability to improve upon their communications about natural gas safety. Therefore, the NTSB recommends that PHMSA identify effective means for natural gas distribution pipeline operators to communicate with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system and implement a plan to help operators drive continuous improvement in public awareness of natural gas safety. The NTSB further recommends that API review the findings and plan from PHMSA’s actions on P-25-3 and update its RP 1162 to provide specific guidance to natural gas distribution pipeline operators on effective safety communication with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system.

2.5.1 Natural Gas Alarms

Public awareness is an effective tool to encourage adoption of safety devices like natural gas alarms. The first edition of API RP 1162 requires that public awareness programs include safety messages about the awareness of hazards and prevention measures as well as leak recognition and response but does not specifically require these programs to disseminate safety messages about natural gas alarms. UGI’s public awareness materials distributed before the accident were consistent with federal regulations, and although the materials promoted the use of smoke and carbon monoxide alarms, they did not address natural gas alarms. Following the accident, UGI now includes safety messages encouraging the purchase of natural gas alarms in its public awareness materials. The NTSB concludes that installing natural gas alarms can alert people of a gas leak so they can evacuate the area; however, natural gas customers may not be aware of the necessity of such alarms.

The NTSB believes that messages about the benefits of natural gas alarms are critically important and could save lives when natural gas alarms are installed. The NTSB further believes that the natural gas industry can help shape the effectiveness of public awareness program delivery methods so that people in businesses, schools, residences, and other places of congregation are better informed, both about natural gas hazards and the necessity of natural gas alarms. The American Gas Association, which represents natural gas pipeline operators throughout the US, can facilitate industry efforts to improve public awareness program delivery methods and to improve safety, most critically through increasing the installation of natural gas alarms. Therefore, the NTSB recommends that the American Gas Association share the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, with its members, encouraging them to evaluate the effectiveness of their current delivery methods of public awareness programs and to promote the installation of natural gas alarms in businesses, residences, and other places of congregation that they serve.

Evacuation should occur immediately upon detection of the presence of natural gas. In 1976, the NTSB made its first recommendation to require natural gas detection to provide early warning of leaks.[106] Most recently, after a 2016 building explosion in Silver Spring, Maryland, and then again after the 2018 home explosion in Dallas, we made recommendations to the ICC and the NFPA to require natural gas alarms with methane detection in residences (NTSB 2019).[107] We recommended the ICC work with the Gas Technology Institute and NFPA to

[106] As a result of its investigation of an April 22, 1974, natural gas explosion in a commercial building in New York City, the NTSB recommended that the US Department of Housing and Urban Development advance guidelines for the installation of gas detection instruments in buildings. The recommendation was classified Closed—Acceptable Action in 1985 based on the lack of practical and affordable technology at the time.

[107] Over the years the NTSB has referred variously to these systems as methane detectors; methane detection systems; and, as in this report, natural gas alarms.

Incorporate provisions in the International Fuel Gas Code that requires methane detection systems for all types of residential occupancies with gas service. At a minimum, the provisions should cover the installation, maintenance, placement of the detectors, and testing requirements. (P-19-6)[108]

We made a similar recommendation to the NFPA:

In coordination with the Gas Technology Institute and the International Code Council, revise the National Fuel Gas Code, National Fire Protection Association 54 to require methane detection systems for all types of residential occupancies with gas service. At a minimum, the provisions should cover the installation, maintenance, placement of the detectors, and testing requirements. (P-19-7)[109]

Continuous monitoring systems such as a natural gas alarm can provide early warning of a gas leak and can warn people to evacuate well before natural gas ignites.[110] An alarm offers a clear signal that there is an unsafe or emergency condition and, particularly in a workplace environment in which fire drills are a familiar practice, tells employees what they must do—evacuate. In the case of this accident, an alarm would have made it clear to Palmer employees that an emergency existed.

Palmer's evacuation procedures at the time of the accident directed employees to leave the building when a fire alarm sounded. Considering the absence of natural gas emergency procedures at Palmer, had the company installed natural gas alarms before the accident, the sound of the alarm would have warned Palmer employees to evacuate before the explosion. Further, for those who were worried that evacuating would compromise their employment, an alarm would give them the reassurance they were doing the right thing. Therefore, the NTSB concludes that had natural gas alarms been installed inside Buildings 1 and 2, an alarm could have alerted employees to the natural gas leak, likely prompting them to evacuate,

[108] NTSB Safety Recommendation P-19-6 is classified Open—Unacceptable Response based on pending adoption of provisions requiring methane detection systems in residences into the IFGC.

[109] NTSB Safety Recommendation P-19-7 is classified Open—Acceptable Alternate Response based on the pending incorporation of NFPA 715 into NFPA 54 or other appropriate code.

[110] Although it was not the case in this accident, odorant can be stripped from natural gas in certain situations. The NTSB investigation of the Dallas explosion found that the soil had absorbed and depleted the natural gas odorant, eliminating the opportunity for occupants to detect it.

reducing or eliminating the fatal consequences of the explosion. Following the accident, Palmer did install natural gas alarms.

Recognizing the safety benefits of natural gas alarms in building evacuation and emergency response, some pipeline operators have begun to install natural gas alarms in buildings with natural gas service (Leon 2022). In 2020, the ICC reported that the NFPA was developing NFPA 715, "Standard for the Installation of Fuel Gases Detection and Warning Equipment." The standard was issued in 2022 and covers the "selection, design, application, installation, location, performance, inspection, testing, and maintenance of fuel gas detection and warning equipment in buildings and structures" (NFPA 2023). Like all standards, NFPA 715 offers detailed technical criteria that can be used to meet a code, however, it has not yet been incorporated into NFPA 54. The NTSB believes that NFPA 715 is a comprehensive standard that could be incorporated by reference into the fuel gas codes. Therefore, the NTSB recommends that the ICC revise the IFGC to provide for required installation of natural gas alarms that meet the specifications of NFPA 715 for buildings that use natural gas. The NTSB likewise recommends that the NFPA revise NFPA 54 (the National Fuel Gas Code) to provide for required installation of natural gas alarms that meet the specifications of NFPA 715 for buildings that use natural gas.

Although some states incorporate NFPA and ICC codes into their laws by reference, states vary in which codes they adopt, enforcement mechanisms, and general laws pertaining to the use of natural gas and natural gas alarms in buildings where people congregate.[111] The NTSB concludes that because adoption of codes and other rules related to natural gas alarms depends on state and local policies, widespread requirement of natural gas alarms will depend on state and local action. Therefore, the NTSB recommends that 50 states, the Commonwealth of Puerto Rico, and the District of Columbia require the installation of natural gas alarms that meet the specifications of NFPA 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak. The NTSB has investigated accidents in which a natural gas leak caused an explosion after the gas migrated from the site of the leak to the site of the explosion, from home explosions in Annandale, Virginia, and Bowie, Maryland, in the 1970s, to South Jordan, Utah, in 2024 (NTSB 1972, NTSB 1974).[112]

[111] *Buildings where people congregate* include schools, workplaces, and recreational facilities.

[112] In the Annandale and Bowie accidents, the explosions occurred about 240 feet and 110 feet away from the leaks, respectively. In the South Jordan accident (PLD25FR001), subsurface gas extended about 250 feet from the leak.

2.5.2 Companies' Emergency Response Procedures

As a private company, Palmer is regulated by OSHA under its authority to set health and safety standards for private-sector employers. Emergencies can be either natural or manmade, and some can be anticipated and planned for. Emergency response procedures can reduce serious injury or loss of life. OSHA does not have an occupational safety and health standard requiring natural gas emergency response procedures, however. During its postaccident inspection of the March 24 incident, OSHA issued several citations to Palmer. None of the regulations cited would have required the company to have an emergency response plan that addresses natural gas hazards.

According to the American Gas Association, about 5.6 million businesses receive natural gas service. As with Palmer, businesses with natural gas service are not required by OSHA to have an emergency response procedure for a gas leak or related training for employees. Palmers' Red Book had no procedures that addressed natural gas emergencies. Palmer had consulted federal and state agency guidance as well as the NFPA when developing the Red Book. The Red Book addressed other procedures and safety measures required by OSHA—for example, evacuation routes and documentation of fatalities and serious injuries—so it is likely that the company would have included natural gas emergency response procedures had these been required.

As seen in this accident, companies may not recognize a natural gas leak as a serious hazard that needs to be addressed in their emergency response procedures. There are no requirements for natural gas emergency response procedures in the IFGC, which Pennsylvania has adopted. A federal requirement mandating workplace natural gas emergency response procedures could prevent a similar accident to the one in this report. The NTSB concludes that when businesses that use natural gas do not have natural gas emergency procedures and training, employees may be unaware or unsure of the steps they should take if they smell natural gas, thus placing them at risk should a leak occur. With no OSHA regulation specifically requiring an emergency response procedure for natural gas leaks, companies lack official direction on how to protect their workers from natural gas hazards in their buildings. Therefore, the NTSB recommends that OSHA require employers whose facilities use natural gas to implement natural gas emergency procedures. After the accident, Palmer developed natural gas emergency response procedures and workplace safety trainings in both English and Spanish, addressing the safety issue of delayed evacuation during a natural gas leak.

An emergency response procedure can prepare building occupants to respond if a natural gas leak occurs or if a natural gas alarm sounds. Neither of the fuel gas codes—the IFGC, which Pennsylvania has adopted, and NFPA 54, which other states have adopted—contain requirements for natural gas emergency response procedures. The IFC (the fire code adopted by Pennsylvania) requires a fire safety and evacuation plan, but it is not specific to natural gas; similarly, the NFPA fire code (NFPA 1) also does not contain a natural gas–specific emergency procedure.

Model codes like the IFC, IFGC, NFPA 1, and NFPA 54 incorporate consensus standards to protect against hazardous conditions. The code development process is participatory and transparent, establishing broadly accepted code requirements that are adapted and adopted by state and local jurisdictions. The NTSB thus concludes that the consensus-based nature and wide reach of the model codes, such as building or fire codes, make them effective instruments to address natural gas–related risks to employees of businesses that use natural gas. Although these codes may include the fuel gas codes IFGC and NFPA 54, other codes such as the fire codes may be appropriate locations for natural gas emergency response procedures. As noted earlier, the ICC administers the IFC and IFGC. Therefore, the NTSB recommends that the ICC revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures. The NTSB likewise recommends that the NFPA revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures.

2.6 Valve Accessibility

During a natural gas emergency such as an explosion or fire, valves along the gas distribution lines are operated to shut off the flow of gas, assisting gas technicians and local emergency responders who are at the scene. Gas continuing to flow into the system can delay emergency response operations and place responders at risk of injury from an ongoing gas fire or secondary explosion.

During the emergency response, the UGI mechanic followed company procedures for closing valves to isolate the natural gas system, working with UGI supervisors to determine which valves to close and other steps to isolate the system. As is typical during the response to an accident involving gas distribution systems, the UGI mechanic attempted to close the valves closest to the accident; these were all secondary valves. Pipeline operators often choose to close the valves closest to the leak to limit the impacted area and reduce the time it takes to burn off the remaining gas in the affected area.

After the UGI mechanic closed the first valve about 5:30 p.m., he encountered difficulty locating the next valve necessary to shut off the rest of the gas flow. The mechanic found a valve with a gas cover in the area, but the valve itself had no plastic tag with a valve number. In July 2024, UGI excavated the site at the NTSB's request and discovered that the correct gas valve had been paved over, and the mechanic had likely been looking at a nearby water valve. Because the UGI mechanic could not positively identify this valve as the correct one, he moved on to two other valves to fully isolate the system. The second of these valves (at South 4th Avenue and Penn Avenue) was not accessible until dirt and debris in the valve box was removed, so it was not closed until 6:15 p.m. Although this valve was designated as a secondary valve, it had been inspected by UGI about 12 months before the accident, and according to UGI's records, the valve box was cleaned at that time. Nonetheless, dirt and debris had accumulated again and delayed isolation of the gas distribution system.

The NTSB reviewed a 2018 image of South 2nd Avenue and Penn Avenue, in which a pair of water valves (valves A and B) are visible but not the gas valve, which was found to be paved over when UGI excavated the valve in 2024. UGI's valve maintenance procedures include 5-year inspections for secondary valves, indicating that UGI would have attempted to inspect this valve while it was paved over, including its most recent documented inspection on March 23, 2021. However, there is no evidence that UGI was aware that the valve had been paved over. In communications with the NTSB, UGI pointed out that the presence of water valve A, which had a gas cover, and suggested that UGI inspectors may have inspected the wrong valve, since both operate in a similar manner. The NTSB has not identified evidence that contradicts this theory, but it was not possible to determine definitively why the paved-over valve was not identified during the 2021 inspection (or previous inspections). The inaccessibility of the paved-over valve and the debris within another valve, both of which were relevant to the emergency response, demonstrates that deficiencies in UGI's valve maintenance program reduced UGI's ability to quickly isolate its system following a leak. The NTSB concludes that UGI did not effectively inspect and maintain its valves through its valve maintenance program, leading to a delay in shutting off gas to the affected area.

After the accident, UGI requested that West Reading Borough make sure water valves were marked with appropriate covers. UGI has also implemented an enhanced valve maintenance program including the use of marker balls to support proper valve identification. The NTSB believes that this effort will improve UGI's valve maintenance program by better equipping UGI inspectors to confirm valve locations.

In this accident, the most expedient valves to access to shut off the gas were secondary valves, and the critical valves (subject to a more-frequent inspection schedule) were not used. The GPTC Guide suggests factors for a natural gas pipeline operator to consider when designating what UGI referred to as critical valves (those defined by 49 *CFR* 192.747 as valves necessary for the safe operation of a distribution system, also known in the industry as operating or emergency valves) on high-pressure distribution lines. These include the total number and type of customers, particularly hospitals, schools, and commercial or industrial users that would be affected by outage or emergency; the number of valves necessary to isolate the area; and the time required for available personnel to isolate the system. The NTSB reviewed UGI's criteria for designating its critical valves, and although the criteria considered the number of customers between critical valves, the criteria made no reference to whether UGI also considered the type of customer or an estimate of the time required to isolate the system. Therefore, the NTSB concludes that because customers vary significantly in the number of occupants or residents, criteria for designating emergency valves that only count customers may not accurately reflect who could be affected by a natural gas outage or emergency or the severity of the effect.

Federal regulations offer criteria for the installation of distribution valves, and GPTC offers guidance for consideration of valve locations, including those necessary for the safe operation of a distribution system, or what UGI called critical valves. The regulations give natural gas operators discretion within those parameters to determine the best location of their valves. As a state-certified program, the PA PUC evaluates each operator's implementation of the requirements of 49 *CFR* 192.747 and determines whether the implementation is reasonable and will result in an effective isolation plan. Therefore, the NTSB recommends that the PA PUC assess the methodology used by natural gas pipeline operators to determine where emergency valves should be located to ensure the operators are properly considering consequences and emergency response times as well as population sizes.

2.7 Withholding Safety-Related Information from the NTSB

PHMSA requires pipeline operators to evaluate risks from all threats to the pipeline system integrity through their DIMPs. In our investigation of the March 24, 2023, explosion, the NTSB sought information on the PA PUC's observations and oversight of UGI, requesting DIMP inspection reports from the PA PUC in June 2023. During inspections, the PA PUC collects and analyzes data on an operator's DIMP and determines if the program complies with pipeline safety regulations; this information is then documented in inspection reports. The PA PUC declined to produce the reports, citing state security information nondisclosure laws that support withholding information from "members of the public" and treating the NTSB as a member of the public. Therefore, in September 2023, the NTSB removed the PA PUC as a party to the investigation, after which the PA PUC could not participate in information sharing among parties during the investigation. During its time as a party, PA PUC was otherwise responsive to the NTSB and assisted in the investigation. The NTSB then issued a subpoena for the reports; after lengthy legal action, the NTSB was able to obtain the reports from the PA PUC in April 2024.

Federal law authorizes the NTSB to require, by subpoena or otherwise, the production of necessary evidence during an accident investigation.[113] Further, federal regulations allow the NTSB to obtain any information related to an accident under investigation.[114] The PA PUC's inspection records of UGI's DIMP were material to the investigation because they contained information on UGI's knowledge of and compliance with pipeline safety regulations and safety bulletins or notifications from PHMSA or other agencies. The NTSB thus concludes that the PA PUC's refusal to provide investigative information pursuant to the NTSB's federal authority added to delays in the investigation and safety recommendations. The NTSB recognizes Pennsylvania's concern about the security of pipeline information and the ramifications of potential disclosure. However, the NTSB has processes that prevent the release of information that could be harmful to individuals or to the public. Therefore, the NTSB recommends that the Commonwealth of Pennsylvania review its statutes and amend them to clarify that confidential security information disclosure restrictions do not apply to the NTSB when it is conducting an accident investigation.

[113] Title 49 U.S.C. Section 1113.

[114] Title 49 *CFR* 831.13.

3 Conclusions

3.1 Findings

1. Neither of the following issues were causal to the accident: (1) pipeline overpressurization or (2) local emergency responder actions.
2. Natural gas migrated from the Aldyl A retired service tee through the ground then into the R.M. Palmer Company Building 2 basement, chocolate pipe conduits, and Building 1, and fueled the explosion in the Building 2 basement.
3. The 1982 retired service tee leaked because of degradation caused by exposure to elevated temperatures; more specifically, slow crack growth of the Aldyl A tower shell and thermal decomposition of the Delrin insert.
4. Steam escaping through the crack of the corroded steam pipe significantly elevated the ground temperature at the location of the retired service tee, which accelerated its degradation and ultimately led to its failure.
5. R.M. Palmer Company's lack of awareness of corrosion-induced wall loss on the steam pipe from Building 1 to Building 2 left the steam pipe vulnerable to localized shear and cracking when external loads changed, which led to steam heating the ground near the retired service tee after UGI Corporation's 2021 service tee replacement project.
6. Had R.M. Palmer Company implemented natural gas emergency procedures and trained their employees and managers on them before the accident, the employees and managers could have understood the danger they faced and could have responded by immediately evacuating and moving to a safe location away from both buildings.
7. Because UGI Corporation did not have sufficient threat information available for analysis in its distribution integrity management program, it could not effectively evaluate and address the risk to pipeline integrity of its plastic piping in elevated temperature environments.
8. Given the widespread adoption of plastic piping, including Aldyl A assets, and the unreliability of historical asset records, operators may not be aware of the locations of their plastic natural gas assets that are vulnerable to degradation in elevated temperature environments, thus appropriate mitigations may not be in place.
9. The severity of this accident, combined with the documented history of failure of Aldyl A service tees with Delrin inserts, indicates a risk associated with the continued use of these components.
10. Had UGI Corporation developed procedures and training for its field crews to report potential sources of elevated temperatures (such as steam pipes)

found in the vicinity of natural gas assets, the threat posed by the steam pipe could have been identified and assessed through UGI's distribution integrity management program, and mitigative measures could have been implemented.

11. Additional industry guidance highlighting the threat to pipeline integrity of plastic pipeline exposure to elevated temperatures could improve awareness of this threat so that other operators may identify and effectively manage it through their distribution integrity management programs.
12. By not addressing the threat posed by the steam pipe, UGI Corporation's distribution integrity management program was not effective in preventing the accident.
13. The omission from the Pennsylvania One Call System of certain assets transporting high-temperature materials like steam that are located in a public right-of-way can pose a risk to anyone excavating in the vicinity.
14. Broad nationwide adoption of the Common Ground Alliance's recommended Best Practice 3-26 on 811 center membership can help prevent accidents similar to this one by increasing awareness of underground private assets, like some steam pipes, that cross public rights-of-way.
15. Natural gas pipeline operator public awareness programs may not reach members of the public in places of congregation or in multifamily residential buildings who do not directly receive bill stuffers; thus, these members of the public may be unaware of the natural gas safety guidance to immediately report a natural gas odor.
16. Installing natural gas alarms can alert people of a gas leak so they can evacuate the area; however, natural gas customers may not be aware of the necessity of such alarms.
17. Had natural gas alarms been installed inside Buildings 1 and 2, an alarm could have alerted employees to the natural gas leak, likely prompting them to evacuate, reducing or eliminating the fatal consequences of the explosion.
18. Because adoption of codes and other rules related to natural gas alarms depends on state and local policies, widespread requirement of natural gas alarms will depend on state and local action.
19. When businesses that use natural gas do not have natural gas emergency procedures and training, employees may be unaware or unsure of the steps they should take if they smell natural gas, thus placing them at risk should a leak occur.
20. The consensus-based nature and wide reach of the model codes, such as building or fire codes, make them effective instruments to address natural gas–related risks to employees of businesses that use natural gas.

21. UGI Corporation did not effectively inspect and maintain its valves through its valve maintenance program, leading to a delay in shutting off gas to the affected area.
22. Because customers vary significantly in the number of occupants or residents, criteria for designating emergency valves that only count customers may not accurately reflect who could be affected by a natural gas outage or emergency or the severity of the effect.
23. The Pennsylvania Public Utility Commission's refusal to provide investigative information pursuant to the National Transportation Safety Board's federal authority added to delays in the investigation and safety recommendations.

3.2 Probable Cause

The National Transportation Safety Board determines that the probable cause of the explosion was degradation of a retired 1982 Aldyl A polyethylene service tee with a Delrin polyacetal insert that allowed natural gas to leak and migrate underground into the R.M. Palmer Company candy factory buildings, where it was ignited by an unknown source. Contributing to the degradation of the service tee and insert were significantly elevated ground temperatures from steam escaping R.M. Palmer Company's corroded underground steam pipe, located near the service tee, that had been unmarked and cracked. Contributing to the steam pipe crack was soil movement and R.M. Palmer Company's lack of awareness of the pipe's corroded state. Contributing to the natural gas leak was UGI Corporation's lack of awareness of the nearby steam pipe, which led to an incomplete integrity management program evaluation that did not consider or manage the risk posed by the steam pipe. Contributing to the accident's severity was R.M. Palmer Company's insufficient emergency response procedures and training of its employees, who did not understand the hazard and did not evacuate the buildings before the explosion.

4 Recommendations

4.1 New Recommendations

As a result of this investigation, the National Transportation Safety Board makes the following new safety recommendations.

To the Pipeline and Hazardous Materials Safety Administration:

Issue an advisory bulletin to all regulated natural gas distribution pipeline operators referencing distribution integrity management program regulations and encouraging operators to:

- Complete a one-time inventory of all plastic assets that are located in environments that experience or are at risk of elevated temperatures;
- Continue, during maintenance and new construction projects, to identify plastic assets that are in elevated temperature environments; and
- Evaluate and mitigate risks to deter the degradation of these assets. (P-25-1)

Issue an advisory bulletin that reviews the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, and advises all regulated natural gas distribution pipeline operators to address the risk associated with Aldyl A service tees with Delrin inserts, including replacing or remediating them. (P-25-2)

Identify effective means for natural gas distribution pipeline operators to communicate with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system and implement a plan to help operators drive continuous improvement in public awareness of natural gas safety. (P-25-3)

To the Occupational Safety and Health Administration:

Require employers whose facilities use natural gas to implement natural gas emergency procedures. (P-25-4)

To 50 States, the Commonwealth of Puerto Rico, and the District of Columbia:

Require the installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak. (P-25-5)

To the Commonwealth of Pennsylvania:

Modify your Underground Utility Line Protection Law to require all owners and operators of pipelines transporting steam or other high-temperature materials located in public rights-of-way to register their assets with the Pennsylvania One Call System. (P-25-6)

Review your statutes and amend them to clarify that confidential security information disclosure restrictions do not apply to the National Transportation Safety Board when it is conducting an accident investigation. (P-25-7)

To the Pennsylvania Public Utility Commission:

Assess the methodology used by natural gas pipeline operators to determine where emergency valves should be located to ensure the operators are properly considering consequences and emergency response times as well as population sizes. (P-25-8)

To the American Gas Association:

Share the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, with your members, encouraging them to evaluate the effectiveness of their current delivery methods of public awareness programs and to promote the installation of natural gas alarms in businesses, residences, and other places of congregation that they serve. (P-25-9)

To the American Petroleum Institute:

Review the findings and plan from the Pipeline and Hazardous Materials Safety Administration’s actions on P-25-3 and update your Recommended Practice 1162 to provide specific guidance to natural gas distribution pipeline operators on effective safety communication with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system. (P-25-10)

To the Gas Piping Technology Committee:

Develop guidance for natural gas pipeline operators to ensure that their distribution integrity management programs appropriately assess and address threats to plastic pipelines posed by nearby assets that may elevate the temperature of the environment near the pipeline. (P-25-11)

To the Common Ground Alliance:

Identify and pursue opportunities for improving adoption of your best practices on 811 center membership, including updating your best practices guide and encouraging states to adopt the updated guidelines. (P-25-12)

To the International Code Council:

Revise the International Fuel Gas Code to provide for required installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 for buildings that use natural gas. (P-25-13)

Revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures. (P-25-14)

To the National Fire Protection Association:

Revise National Fire Protection Association 54 (the National Fuel Gas Code) to provide for required installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 for buildings that use natural gas. (P-25-15)

Revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures. (P-25-16)

To UGI Corporation:

Inventory all your plastic natural gas assets that may be located in elevated temperature environments and address the risk associated with these assets. (P-25-17)

To R.M. Palmer Company:

Revise your natural gas emergency procedure to direct all employees to immediately evacuate upon smelling natural gas odorant and to specify a safe evacuation location. (P-25-18)

4.2 Previously Issued Recommendation Reiterated in This Report

The National Transportation Safety Board reiterates the following safety recommendation.

To the Pipeline and Hazardous Materials Safety Administration:

> Evaluate industry's implementation of the gas distribution pipeline integrity management requirements and develop updated guidance for improving their effectiveness. The evaluation should specifically consider factors that may 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. (P-21-2)

Safety Recommendation P-21-2 is reiterated in section 2.3 of this report.

BY THE NATIONAL TRANSPORTATION SAFETY BOARD

JENNIFER L. HOMENDY Chairman	MICHAEL GRAHAM Member
ALVIN BROWN Vice Chairman	THOMAS CHAPMAN Member
	J. TODD INMAN Member

Report Date: March 18, 2025

Appendixes

Appendix A: Investigation

The National Transportation Safety Board (NTSB) was notified of this accident on March 25, 2023. An NTSB investigator arrived at the scene on March 25, and the NTSB launched an official investigation on March 28. The NTSB team consisted of an investigator-in-charge, pipeline operations investigators, an emergency response investigator, integrity management investigators, a materials laboratory investigator, a fire investigator, a video recording investigator, a systems safety investigator, and a photograph specialist investigator. The parties to the investigation are the Pipeline and Hazardous Materials Safety Administration, West Reading Fire Department, Pennsylvania State Police, Spring Township Fire Department, West Reading Borough Police, UGI Utilities Inc. (a UGI Corporation subsidiary), and R.M. Palmer Company.

Appendix B: Consolidated Recommendation Information

Title 49 *United States Code* 1117(b) requires the following information on the recommendations in this report.

For each recommendation—

(1) a brief summary of the Board's collection and analysis of the specific accident investigation information most relevant to the recommendation;

(2) a description of the Board's use of external information, including studies, reports, and experts, other than the findings of a specific accident investigation, if any were used to inform or support the recommendation, including a brief summary of the specific safety benefits and other effects identified by each study, report, or expert; and

(3) a brief summary of any examples of actions taken by regulated entities before the publication of the safety recommendation, to the extent such actions are known to the Board, that were consistent with the recommendation.

To the Pipeline and Hazardous Materials Safety Administration:

P-25-1

Issue an advisory bulletin to all regulated natural gas distribution pipeline operators referencing distribution integrity management program regulations and encouraging operators to:

- Complete a one-time inventory of all plastic assets that are located in environments that experience or are at risk of elevated temperatures;
- Continue, during maintenance and new construction projects, to identify plastic assets that are in elevated temperature environments; and
- Evaluate and mitigate risks to deter the degradation of these assets.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.3, Insufficient Consideration of Known Threats from Plastic Piping. Information supporting (b)(1) can be found on pages 64–69; (b)(2) and (b)(3) are not applicable.

P-25-2

Issue an advisory bulletin that reviews the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, and advises all regulated natural gas distribution pipeline operators to address the risk associated with Aldyl A service tees with Delrin inserts, including replacing or remediating them.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.3, Insufficient Consideration of Known Threats from Plastic Piping. Information supporting (b)(1) can be found on pages 64–69; (b)(2) and (b)(3) are not applicable.

P-25-3

Identify effective means for natural gas distribution pipeline operators to communicate with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system and implement a plan to help operators drive continuous improvement in public awareness of natural gas safety.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5, Public Awareness and Preparedness. Information supporting (b)(1) can be found on pages 71–73; (b)(2) and (b)(3) are not applicable.

To the Occupational Safety and Health Administration:

P-25-4

Require employers whose facilities use natural gas to implement natural gas emergency procedures.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.2, Companies' Emergency Response Procedures. Information supporting (b)(1) can be found on pages 77–78; (b)(2) and (b)(3) are not applicable.

To 50 States, the Commonwealth of Puerto Rico, and the District of Columbia:

P-25-5

Require the installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 in businesses, residences, and other buildings where people congregate that could be affected by a natural gas leak.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.1, Natural Gas Alarms. Information supporting (b)(1) can be found on pages 73–76; (b)(2) and (b)(3) are not applicable.

To the Commonwealth of Pennsylvania:

P-25-6

Modify your Underground Utility Line Protection Law to require all owners and operators of pipelines transporting steam or other high-temperature materials located in public rights-of-way to register their assets with the Pennsylvania One Call System.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.4, Unmarked Private Assets in Public Rights-of-Way. Information supporting (b)(1) can be found on pages 69–71; (b)(2) and (b)(3) are not applicable.

P-25-7

Review your statutes and amend them to clarify that confidential security information disclosure restrictions do not apply to the National Transportation Safety Board when it is conducting an accident investigation.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.7, Withholding Safety-Related Information from the NTSB. Information supporting (b)(1) can be found on pages 80–81; (b)(2) and (b)(3) are not applicable.

To the Pennsylvania Public Utility Commission:

P-25-8

Assess the methodology used by natural gas pipeline operators to determine where emergency valves should be located to ensure the operators are properly considering consequences and emergency response times as well as population sizes.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.6, Valve Accessibility. Information supporting (b)(1) can be found on pages 78–80; (b)(2) and (b)(3) are not applicable.

To the American Gas Association:

P-25-9

Share the details of the March 24, 2023, natural gas–fueled explosion and fire in West Reading, Pennsylvania, with your members, encouraging them to evaluate the effectiveness of their current delivery methods of public awareness programs and to promote the installation of natural gas alarms in businesses, residences, and other places of congregation that they serve.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5, Public Awareness and Preparedness. Information supporting (b)(1) can be found on pages 71–73; (b)(2) and (b)(3) are not applicable.

To the American Petroleum Institute:

P-25-10

Review the findings and plan from the Pipeline and Hazardous Materials Safety Administration’s actions on P-25-3 and update your Recommended Practice 1162 to provide specific guidance to natural gas distribution pipeline operators on effective safety communication with people who live, work, or congregate within the coverage area of a natural gas distribution pipeline system.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5, Public Awareness and Preparedness. Information supporting (b)(1) can be found on pages 71–73; (b)(2) and (b)(3) are not applicable.

To the Gas Piping Technology Committee:

P-25-11

Develop guidance for natural gas pipeline operators to ensure that their distribution integrity management programs appropriately assess and address threats to plastic pipelines posed by nearby assets that may elevate the temperature of the environment near the pipeline.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.3, Insufficient Consideration of Known Threats from Plastic Piping. Information supporting (b)(1) can be found on pages 64–69; (b)(2) and (b)(3) are not applicable.

To the Common Ground Alliance:

P-25-12

Identify and pursue opportunities for improving adoption of your best practices on 811 center membership, including updating your best practices guide and encouraging states to adopt the updated guidelines.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.4, Unmarked Private Assets in Public Rights-of-Way. Information supporting (b)(1) can be found on pages 69–71; (b)(2) and (b)(3) are not applicable.

To the International Code Council:

P-25-13

Revise the International Fuel Gas Code to provide for required installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 for buildings that use natural gas.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.1, Natural Gas Alarms. Information supporting (b)(1) can be found on pages 73–76; (b)(2) and (b)(3) are not applicable.

P-25-14

Revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.2, Companies' Emergency Response Procedures. Information supporting (b)(1) can be found on pages 77–78; (b)(2) and (b)(3) are not applicable.

To the National Fire Protection Association:

P-25-15

Revise National Fire Protection Association 54 (the National Fuel Gas Code) to provide for required installation of natural gas alarms that meet the specifications of National Fire Protection Association 715 for buildings that use natural gas.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.1, Natural Gas Alarms. Information supporting (b)(1) can be found on page 115; (b)(2) is not applicable; and (b)(3) is not applicable.

P-25-16

Revise the appropriate nationally adopted building or fire codes to provide for natural gas emergency procedures.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.5.2, Companies' Emergency Response Procedures. Information supporting (b)(1) can be found on pages 77–78; (b)(2) and (b)(3) are not applicable.

To UGI Corporation:

P-25-17

Inventory all your plastic natural gas assets that may be located in elevated temperature environments and address the risk associated with these assets.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.3, Insufficient Consideration of Known Threats from Plastic Piping. Information supporting (b)(1) can be found on pages 64–69; (b)(2) and (b)(3) are not applicable.

To R.M. Palmer Company:

P-25-18

Revise your natural gas emergency procedure to direct all employees to immediately evacuate upon smelling natural gas odorant and to specify a safe evacuation location.

Information that addresses the requirements of 49 *USC* 1117(b), as applicable, can be found in section 2.2.2, Delayed Evacuation. Information supporting (b)(1) can be found on pages 62–63; (b)(2) and (b)(3) are not applicable.

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STAFF-DR-02-020

REQUEST:

Refer to Case No. 2021-00190,[2] the Direct Testimony of John Spanos, Attachment JS-1, Depreciation Study, page 7 of 237 and the Direct Testimony of John Spanos (Spanos Direct Testimony), Attachment JJS-1, Depreciation Study, page 7 of 241 in this matter. Explain why Production Plant is not included in the most recent Depreciation Study Calculation's Original Cost, Accrual Rates and Amounts.

RESPONSE:

The Company's Production Plant assets were all retired in 2022 since the depreciation study filed in Case No. 2021-00190.

Please see Case No. 2021-00405 for additional background regarding the retirement and the Commission's order on the recovery of propane related expenses.

PERSON RESPONSIBLE: John J. Spanos
Jefferson "Jay" P. Brown

[2] Case No. 2021-00190, *Electronic Application of Duke Energy Kentucky, Inc. For: 1) An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs, and 3) All Other Required Approvals, Waivers, and Relief.*

STAFF-DR-02-021

REQUEST:

Refer to Case No. 2021-00190, Spanos Direct Testimony, Attachment JS-1, Depreciation Study, page 7 of 237 and the Spanos Direct Testimony, Attachment JJS-1, Depreciation Study, page 7 of 241 in this matter. Explain the decrease in the proposed General Plant rate.

RESPONSE:

The primary cause of the decrease in the General Plant depreciation rate is the high level of additions for longer lived assets placed in service since the depreciation study conducted for Case No. 2021-00190. The original cost for General Plant was $4.58 million as of December 31, 2017, and increased to $17.15 million as of September 30, 2024. The majority of the growth for General Plant related to Account 297.00 which has a 15-year life. Additionally, Account 294.00, which has a 25-year life, caused the composite rate to decrease. The resulting composite rate has decreased primarily due to these two accounts.

PERSON RESPONSIBLE: John J. Spanos

STAFF-DR-02-022

REQUEST:

Refer to Spanos Direct Testimony, Attachment JJS-1, Depreciation Study, Page 20 of 241. For accounts listed under General Plant, explain the variance in both rate and composite remaining life of each one compared to the 2021 Depreciation Study.

RESPONSE:

As mentioned in STAFF-DR-02-021, the increased level of additions to the longer lived asset classes since the previous study had a significant impact on the rates for each account. The original cost for most of the accounts in General Plant more than doubled since the prior study. Therefore, the high levels of younger assets will increase the composite remaining life for the account. Additionally, the assets that were retired had a higher reserve to plant ratio and short remaining life. Consequently, the vintage breakdown of each account (see Part IX of the Depreciation Study), has more assets with a longer remaining life since they are new, which means the depreciation rate is lower since the investment is so recent.

PERSON RESPONSIBLE: John J. Spanos

Duke Energy Kentucky
Case No. 2025-00125
STAFF's Second Request for Information
Date Received: July 1, 2025

STAFF-DR-02-023

REQUEST:

Refer to the Direct Testimony of Jefferson Brown (Brown Direct Testimony), page 17, lines 14-16. Confirm that Duke Kentucky is asking for the Rider PMM to be effective five years in addition to the seven-year initial approved period[3] or a total of 12 years. If not confirmed, explain the response.

RESPONSE:

Yes, The Company is proposing an additional 5 years to be approved for a total of 12 years.

PERSON RESPONSIBLE: Jefferson "Jay" P. Brown

[3] Case No. 2021-00190, Dec. 12, 2021 Order, Attachment A, Settlement at 7.

Duke Energy Kentucky
Case No. 2025-00125
STAFF's Second Request for Information
Date Received: July 1, 2025

STAFF-DR-02-024

REQUEST:

Refer to the Brown Direct Testimony, page 19, lines 15-16. Provide specific cost breakdown of the estimated expense provided.

RESPONSE:

Subsequent to the filing of the Direct Testimony in this proceeding it was discovered that the original estimate for the Aldyl-A project was incomplete and needed to be revised. To clarify, approximately 38 miles of Aldyl-A main replacement will cost about $52 million while an additional cost for 5,455 service replacements is estimated at $32 million. These estimates utilize a 2025 cost basis and rely on current contracts with vendors without escalations. Originally 3,700 Aldyl-A services were estimated. However, after further analysis of Duke Energy Kentucky's system of record, GIS, approximately 5,455 Aldyl-A services were identified, installed between 1964 and 1985.

	Main 38 miles	Services 5,455 services	Total
2028	$ 7,482,560	$ 4,519,860	
2029	$ 11,223,850	$ 6,779,790	
2030	$ 11,223,850	$ 6,779,790	
2031	$ 11,223,850	$ 6,779,790	
2032	$ 11,223,850	$ 6,779,790	
Total Spend	$ 52,377,960	$ 31,639,020	$ 84,016,980

PERSON RESPONSIBLE: Jefferson "Jay" P. Brown
Adam Long, as to estimate.

Duke Energy Kentucky
Case No. 2025-00125
STAFF's Second Request for Information
Date Received: July 1, 2025

CONFIDENTIAL STAFF-DR-02-025
(As to Attachment only)

REQUEST:

Provide a map of the service territory with the Aldyl-A type pipe designated.

RESPONSE:

<u>CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)</u>

Please see STAFF-DR-02-025 Confidential Attachment.

PERSON RESPONSIBLE: Adam Long

CONFIDENTIAL PROPRIETARY TRADE SECRET

STAFF-DR-02-025 CONFIDENTIAL ATTACHMENT

FILED UNDER SEAL

STAFF-DR-02-026

REQUEST:

Refer to the late fee annual reports filed in the post-case filings for Case No. 2021-00190 and the final rehearing Order[4] in that matter.

a. Provide the total amount of late payment charges waived from the rehearing Order to the present date. For the year 2025, provide the month and the amount.

b. Provide the current amount as of the date of this request, of the regulatory asset recorded as a result of the late payment charge waivers.

c. Explain whether Duke Kentucky intends to request to roll that amount into base rates at this time.

d. Explain whether Duke Kentucky intends to continue the late payment waivers.

RESPONSE:

a. The total amount of late payment charges waived for natural gas customers from February 2022 through June 2025 is ~$48,100.

For 2025, the amount of late payment charges waived for natural gas customers by month is below:

Month	Amount
January	~$1,960
February	~$3,800
March	~$4,300
April	~$2,900

[4] Case No. 2021-00190, Jan. 25, 2022, Order at 4-5.

May	~$1,800
June	~$600

b. Due to the immaterial nature of these charges, the Company elected not to record waived late payment charges to a regulatory asset since the last base rate case.

c. The Company did not request to include waived late payment charges in this proceeding.

d. The Company does intend to continue the late payment charge waiver program.

PERSON RESPONSIBLE: Lindsay B. Philemon

Duke Energy Kentucky
Case No. 2025-00125
STAFF's Second Request for Information
Date Received: July 1, 2025

STAFF-DR-02-027

REQUEST:

Refer to the Direct Testimony of Daniel Dane (Dane Direct Testimony) generally. Explain why a 2024 study period was not used, as 2024 would still provide historical data.

RESPONSE:

A 2023 study period was used due to the timing of when the lead-lag study analysis began, at which time 2024 data was not available. I determined based on discussions with the Company that processes in place in 2023 had not substantially changed, making 2023 data reliable for the purposes of determining the Company's cash working capital requirement in this proceeding.

PERSON RESPONSIBLE: Daniel S. Dane

Duke Energy Kentucky
Case No. 2025-00125
STAFF's Second Request for Information
Date Received: July 1, 2025

STAFF-DR-02-028

REQUEST:

Refer to the Dane Direct Testimony, page 7, lines 10-11. Explain why a bank lag was included in the revenue lag calculation. Include in this response whether this is normally included lead lag study standard practice.

RESPONSE:

Including a bank lag in the revenue lag portion of a lead-lag study is a well-established regulatory practice. The bank lag measures the time from when the customer pays to when the utility has access to the funds. The bank lag reflects the delay between receipt of payment and the availability of funds in the utility's account. This can occur due to mail float (for checks), processing time for electronic payments, or bank clearing delays.

From a cash working capital perspective, the utility does not have access to the funds until they are deposited and cleared. Excluding the bank lag would understate the utility's actual cash needs, potentially leading to an under-recovery of working capital in rates.

PERSON RESPONSIBLE: Daniel S. Dane

STAFF-DR-02-029

REQUEST:

Refer to the Dane Direct Testimony, page 11, lines 12-15. Explain how the random sample of invoices were selected.

RESPONSE:

The random sample of 350 invoices was selected from the total Accounts Payable (AP) population (including both invoices and expenses reports, and excluding expenses analyzed elsewhere in the lead-lag study and payments under $100) using a random number generator.

The sample size was based on attaining a confidence interval of +/- 5%, based on a total population of 2,048 line items.

PERSON RESPONSIBLE: Daniel S. Dane

STAFF-DR-02-030

REQUEST:

Explain how the DEBS Service Agreement impacts the lead lag calculation. Include in the response a discussion of invoices, deposits, and customer payments specifically.

RESPONSE:

As described in Mr. Dane's testimony, Duke Energy Kentucky receives various services from DEBS and other affiliated companies. Duke Energy Kentucky pays its affiliates for those services, as well as when an affiliate pays an invoice on its behalf. Billing for affiliate services is performed monthly, with payment occurring through a settlement process by the end of the month following the month of service. Affiliate payments are made electronically. The lead-lag study analyzed 2023 shared services charges, with a resulting expense lead of 41.6 days. Those charges included inter-company receivables, payables, and advances between money pool participants.

PERSON RESPONSIBLE: Daniel S. Dane

Duke Energy Kentucky
Case No. 2025-00125
STAFF's Second Request for Information
Date Received: July 1, 2025

STAFF-DR-02-031

REQUEST:

Refer to Schedule B-2.1 page 4. Explain the calculation of the 29.25 percent used for Common Plant Allocated to Gas.

RESPONSE:

The 29.25 percent used for Common Plant Allocated to Gas is based on the weighted averages resulting from the application of allocation factors to the investment based on Gross Plant as of 12/31/2023. Please see STAFF-DR-02-031 Attachment for a copy of page 356 of the Company's 2023 FERC Form No. 1. The 29.25 percent is the same as the Allocation of Accumulated Provision for Depreciation to Gas. Additionally, page 356 of the Company's 2023 FERC Form No. 1 was utilized for the Common Plant Allocated to Electric in Case No. 2024-00354.

PERSON RESPONSIBLE: Jefferson "Jay" P. Brown

Name of Respondent: Duke Energy Kentucky, Inc.	This report is: (1) ☐ An Original (2) ☑ A Resubmission	Date of Report: 06/14/2024	Year/Period of Report End of: 2023/ Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Electric Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to the order of the Commission or other authorization.

1. COMMON UTILITY PLANT
COMMON PLANT IN SERVICE

Account Title	Bal. Beg. of Yr	Additions (A)	Retirements	Transfers (B)	Balance YE
303 Misc. Intangible Plant	22,425,003	—	0	0	22,425,003
370 Common AMI Meters	—	—	—	—	—
389 Land and Land Rights	1,041,678	—	—	—	1,041,678
390 Struct & Improvements	13,814,128	7,312,014	(42,354)	—	21,083,788
391 Office Furniture & Equipment	758,132	771,499	—	—	1,529,631
Electronic Data Processing	40,535	—		—	40,535
392 Transportation Equipment	—	—	—	—	—
393 Stores Equipment	—	—	—	—	—
394 Tools, Shop & Garage Equip	113,850	—	—	—	113,850
395 Laboratory Equipment	—	—	—	—	—
397 Communication Equipment	4,303,310	3,250,843	(1,077,675)	—	6,476,478
398 Miscellaneous Equipment	95,301	—	—	—	95,301
399 ARO General Plant	787,501	699,481	—	—	1,486,982
Total Common Plt in Service	43,379,438	12,033,837	(1,120,029)	—	54,293,246
CWIP	5,396,957	(5,136,129)	—	—	260,828
Total Common Utility Plant in Ser.	48,776,395	6,897,708	(1,120,029)	—	54,554,074

ALLOCATION OF COMMON PLANT TO UTILITY DEPARTMENTS (C)

Summary by Account Estimated as of 12/31/2023

Gas Department	29.25%	15,957,067
Electric Department	70.75%	38,597,007
	100.00%	54,554,074

(A) Classification of Account 106, Completed Construction Not Classified, included in the Additions column.

(B) Represents reclassification between utility departments and primary plant accounts.

(C) The percentages used to allocate Common Plant to utility departments are the weighted averages resulting from the application of allocation factors to the investment based on Gross Plant as of 12/31/2023.

2. ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF COMMON UTILITY PLANT

Balance - Beginning of Year		27,267,667
Depreciation provision for the year charged to:		
(403) Depreciation Expense (1)	343,390	
(404) Amortization-Limited Term Plant	197,215	
(403.1) Depreciation Expense (1)	509,830	
		1,050,435
Net Charges for Plant Retired:		
Book Cost of Plant Retired	(1,120,029)	
Cost of Removal	(487,803)	
Salvage (Credit)	(3,543)	
		(1,611,375)
Other Items:		
Transfers & Adjustments	—	
		—
Balance - End of the Year		26,706,727

ALLOCATION OF ACCUMULATED PROVISION FOR
DEPRECIATION TO UTILITY DEPARTMENTS (3)

Summary by Account Estimated as of 12/31/2023

Gas Department	29.25%	7,811,718
Electric Department	70.75%	18,895,010
	------	----------
	100.00%	26,706,728

METHOD OF DETERMINATION OF DEPRECIATION
& AMORTIZATION

Common Plant in Service	Rate (4)
Miscellaneous Intangible Plant	Note (2)
Structures and Improvements	2.34%
Office Furniture and Equipment	5.00%
Electronic Data Processing Equipment	10.01%
Tools, Shop & Garage Equipment	4.00%
Transportation & Power Operated Equipment	Note (4)
Communication Equipment	6.67%
Miscellaneous Equipment	6.67%

(1) The Respondent determines its monthly provision for depreciation by the application of rates to the previous month's balance of property capitalized in each primary plant account plus total Account 106 - Completed Construction Not Classified.

(2) The Respondent amortized its investment in Miscellaneous Intangible Plant equally over 60 months for certain projects.

(3) The percentages used to allocate the Common Plant Accumulated Provision for Depreciation balances to utility departments are the weighted averages resulting from the application of allocation factors to the balance of Common Plant Accumulated Provision at 12/31/2023. These factors are based on Gross Plant as of 12/31/2023.

(4) In 1997, the Respondent adopted vintage year accounting for general plant accounts in accordance with FERC Accounting Release No. 15.

(5) The Respondent amortized its investment in Transportation & Power Operated Equipment over the estimated lives of the individual assets.

3. COMMON UTILITY PLANT EXPENSE ACCOUNTS

Common utility plant expense accounts are not maintained, but such expenses are allocated to gas and electric departments principally on one or more of the following bases:

Floor space utilized for buildings and office equipment
General labor - total company
Number of gas and electric customers
IT operations
Numbers of customers
Three factor formula

4. COMMISSION APPROVAL

Prior to establishment of original cost, Messrs. Brenner and Eilers of the respondent and Campbell and Schwartz from Columbia System met with Mr. Smith of the Federal Power Commission to discuss amongst other things, the Federal Power Commission's permission to use the Common Utility Plant accounts. It was pointed out by the representatives of the Respondent that because of the nature of the Respondent's operations it was impossible and impractical to assign certain types of equipment directly to either gas or electric utility plant. Because of the facts presented, Mr. Smith gave the Respondent's respresentatives verbal permission to use the common plant accounts.