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DEPARTMENT OF TRANSPORTATION

Pipeline and Hazardous Materials Safety Administration

49 CFR Parts 190, 195, 196, and 198

[Docket No. PHMSA-2022-0125]

RIN 2137-AF60

Pipeline Safety: Safety of Carbon Dioxide and Hazardous Liquid Pipelines

AGENCY: Pipeline and Hazardous Materials Safety Administration (PHMSA), Department of Transportation (DOT).

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: PHMSA proposes revisions to the Pipeline Safety Regulations to include safety standards and reporting requirements for gas- and liquid-phase carbon dioxide pipelines. PHMSA proposes safety improvements for all carbon dioxide pipelines, including the establishment of an emergency planning zone for improved emergency response and public communications; more prescriptive fracture control requirements; explicit inclusion of carbon dioxide in the definition of a highly volatile liquid; specific requirements for vapor dispersion modeling; and conforming changes to operations, maintenance, and emergency manuals. PHMSA also proposes specific requirements applicable to both hazardous liquid and carbon dioxide pipelines, including enhanced right-of-way inspections to identify geologic hazards and mitigate those threats, and the use of fixed vapor detection and alarm systems at specific highly volatile liquid pipeline facilities. Additionally, PHMSA proposes changes to the conversion to service requirements affecting both hazardous liquid and carbon dioxide pipelines. On May 31 and June 1, 2023, PHMSA held a public meeting to discuss carbon dioxide pipeline safety and

help inform this rulemaking. PHMSA received feedback from members of the public, Tribal government representatives, Tribal advocacy representatives, State pipeline safety program representatives, pipeline safety advocacy groups, first responders and emergency response organizations, and industry experts.

DATES: Individuals interested in submitting written comments on this NPRM must do so by **[INSERT DATE 60 DAYS FROM DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

ADDRESSES: Comments should reference Docket No. PHMSA-2022-0125 and may be submitted in any of the following ways:

1. *E-Gov Web: http://www.regulations.gov*. This site allows the public to enter comments on any Federal Register notice issued by any agency. Follow the online instructions for submitting comments.
2. *Mail:* Docket Management System: U.S. Department of Transportation, 1200 New Jersey Avenue SE, West Building Ground Floor, Room W12-140, Washington, D.C. 20590-0001.
3. *Hand Delivery*: DOT Docket Management System: West Building Ground Floor, Room W12-140, 1200 New Jersey Avenue SE, between 9:00 a.m. and 5:00 p.m. EST, Monday through Friday, except Federal holidays.
4. *Fax:* 202-493-2251.

Instructions: Include the agency name and identify Docket No. PHMSA-2022-0125 at the beginning of your comments. Note that all comments received will be posted without change to *https://www.regulations.gov*, including any personal information provided. If you submit your comments by mail, submit two copies. If you wish to receive confirmation that PHMSA received your comments, include a self-addressed stamped postcard.

Confidential Business Information: Confidential Business Information (CBI) is commercial or financial information that is both customarily and actually treated as private by its owner. Under the Freedom of Information Act (5 U.S.C. 552), CBI is exempt from public disclosure. If your comments in response to this NPRM contain commercial or financial information that is customarily treated as private, that you actually treat as private, and that is relevant or responsive to this NPRM, it is important that you clearly designate the submitted comments as CBI. Pursuant to 49 Code of Federal Regulations (CFR) 190.343, you may ask PHMSA to provide confidential treatment to the information you give to the agency by taking the following steps: (1) mark each page of the original document submission containing CBI as "Confidential;" (2) send PHMSA a copy of the original document with the CBI deleted along with the original, unaltered document; and (3) explain why the information you are submitting is CBI. Submissions containing CBI should be sent to alexandria.colletti@dot.gov. Any comment PHMSA receives that is not explicitly designated as CBI will be placed in the public docket.

Docket: To access the docket, which contains background documents and any comments that PHMSA has received, go to *https://www.regulations.gov*. Follow the online instructions for accessing the docket. Alternatively, you may review the documents in person at DOT's Docket Management Office at the address listed above.

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 *www.regulations.gov*, as described in the system of records notice (DOT/ALL–14 FDMS), which can be reviewed at *www.dot.gov/privacy*.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

I. Executive Summary

A. Purpose of the Regulatory Action

PHMSA proposes a series of revisions to the Federal Pipeline Safety Regulations (PSR) 49 CFR parts 190-199, in response to congressional mandates directing PHMSA to regulate carbon dioxide in the gas and (sub-critical) liquid phases; the anticipated significant expansion of pipeline infrastructure transporting carbon dioxide in all phases due to private sector, State, and Federal initiatives to address climate change; and lessons learned from the February 22, 2020, rupture of a supercritical-phase carbon dioxide pipeline near Satartia, Mississippi. PHMSA expects the proposals in this NPRM—including the modification of regulatory definitions to bring gas- and liquid-phase carbon dioxide pipelines within the scope of PHMSA's part 195 design, installation, operations, maintenance, and reporting requirements; enhanced requirements governing conversion of existing pipelines to part 195 service; bolstered integrity management requirements; and strengthened emergency response communication and coordination requirements for all part 195-regulated pipelines—will ensure any expansion of carbon dioxide pipeline infrastructure occurs in a manner that is safe for nearby communities and pipeline workers, protective of the environment, transparent, and equitable as it supports the greenhouse gas reduction potential of carbon capture, utilization, and sequestration (CCUS or CCS) efforts.

This rulemaking implements a decade-old statutory mandate in the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011[1] (Pub. L. 112-90, 2011 Pipeline Safety Act) to prescribe minimum safety standards for transportation of gaseous-phase carbon dioxide in

[1] Public Law No. 112-90, "Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011," (January 3, 2012).

addition to supercritical- and liquid-phase[2] carbon dioxide. That statute required PHMSA to consider whether to extend existing minimum safety standards in part 195 for transportation of supercritical-phase carbon dioxide to the transportation of carbon dioxide in those additional phases.[3] This regulatory gap is due to the limited (supercritical-phase only) carbon dioxide pipelines in operation in 1991. Recent nationwide, private sector, State, and Federal efforts—in particular, the 2021 Infrastructure Investment and Jobs Act (Pub. L. 117-58), the Inflation Reduction Act of 2022 (Pub. L. 117-169), and their respective implementing regulations and financial incentives—have encouraged significant, near-term commercial interest in the increase of pipelines transporting carbon dioxide (including gas-phase carbon dioxide) as part of a larger buildout of CCUS infrastructure, including capture at industrial facilities and power plants, direct air-capture, increasing opportunities for carbon utilization, and long-term storage facilities. Timely amendment of PHMSA's part 195 is imperative to ensure that the construction of new, greenfield carbon dioxide pipeline infrastructure and the conversion of existing pipelines to part 195 carbon dioxide service is executed in a manner that is transparent and provides defense-in-depth for protection of public safety and the environment.

The February 22, 2020, rupture near Satartia, Mississippi of a supercritical-phase carbon dioxide pipeline operated by Denbury Gulf Coast Pipelines, LLC (Satartia accident) also underscores the adverse public safety and environmental consequences of not addressing the regulatory gap for gas- and liquid-phase carbon dioxide pipelines—as well as the value in

[2] The 2011 Pipeline Safety Act refers to the gaseous and liquid states; however, PHMSA uses the word "phase" in lieu of "state" throughout, for reader ease and consistency with the proposed amendments.
[3] The Research and Special Programs Administration could have included other phases of carbon dioxide in a 1991 final rule but chose not to do so—please see section II.C of this NPRM for further information.

enhancing longstanding part 195 requirements for all carbon dioxide pipelines. The Satartia accident resulted from the full circumferential fracture of a pipeline girth weld caused by a landslide from heavy rains that placed catastrophic axial strain on the pipeline.[4] This accident released 31,405 barrels of supercritical-phase carbon dioxide, sent 45 individuals to hospitals for medical treatment, and prompted the evacuation of approximately 200 residents from the nearby community, which U.S. Census data indicates was a majority-minority, economically-challenged area. As discussed in greater detail in section II.D below, PHMSA's Failure Investigation Report stated the operator's actions and omissions contributed to the accident and its severity. Further, it found that enhanced PHMSA safety regulations, integrity management (IM) programs, and emergency response coordination requirements would help avoid or mitigate similar accidents; see sections I.B, II.D, and proposal discussions within III for further details. The proposed rule is important to protect public safety and the environment as the mileage of pipelines transporting carbon dioxide (in different phases and product stream compositions) increases nationwide.

B. Summary of the Proposed Regulatory Action

This NPRM contains the following proposed changes to PHMSA regulations: (1) amend the statement of scope for part 195 (§ 195.1) and related regulatory definitions (§ 195.2); (2) revise part 195 IM program requirements at § 195.452 to explicitly require all operators of highly volatile liquid (HVL) pipelines (including carbon dioxide pipelines) to perform vapor dispersion analyses consistent with the minimum elements prescribed in a new § 195.456 when determining

[4] PHMSA, Failure Investigation Report, "Denbury Gulf Coast Pipelines, LLC, February 22, 2020" (May 26, 2022), *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf*.

whether their pipelines could affect high consequence areas (HCAs) and therefore are subject to part 195 IM program requirements; (3) amend § 195.402 to require all carbon dioxide pipeline operators to provide training to emergency responders that addresses threats specific to carbon dioxide releases and provide equipment to local first responders for use during an emergency on a carbon dioxide pipeline; (4) amend § 195.402 to provide more robust requirements for operators of all carbon dioxide pipelines to communicate with the public in the event of an emergency; (5) amend § 195.111 to require enhanced fracture control and arrest on carbon dioxide pipelines that are newly constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5; (6) add a new § 195.309 to prescribe requirements for spike hydrostatic pressure testing wherever required by part 195; (7) remove carbon dioxide from the list of acceptable pressure test mediums at § 195.306; (8) amend § 195.5 to require conversions to part 195 service of any hazardous liquid or carbon dioxide pipeline to meet the design and construction requirements of part 195, subparts C and D, as well as to provide enhanced inspection, testing, and evaluation requirements for pipelines converted to carbon dioxide part 195 service; (9) amend § 195.412 to enhance right-of-way inspection requirements on all part 195-regulated pipelines to require operators to have a program to identify and take appropriate actions concerning geologic hazards and reduced depth of cover on their pipelines;[5] (10) introduce a new agricultural area category to existing depth of cover requirements at § 195.248; (11) amend §§ 195.134 and 195.444 to require leak detection systems for carbon dioxide pipeline

[5] For convenience of the reader, and consistent with language at § 195.1 and elsewhere providing for application of various part 195 requirements, PHMSA uses the term "hazardous liquid" pipeline to include hazardous liquid gathering lines, as pertinent.

systems; (12) add §§ 195.263 and 195.429 to require the installation, operation, and maintenance of fixed vapor detection and alarm systems on HVL pipelines (including carbon dioxide pipelines) that are newly constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5; (13) amend § 195.452 to require operators of all pipelines subject to part 195 IM requirements to include risk factors for deleterious constituents in the product stream for assessment scheduling, information analysis, and risk analysis; and for carbon dioxide pipelines subject to part 195 IM requirements, to consider carbon dioxide releases when making emergency flow restricting device (EFRD) determinations and to have fixed vapor detection and alarm systems consistent with the requirements of § 195.263 on existing pipelines that transport HVLs (including carbon dioxide) that are located in or could affect an HCA; (14) amend § 195.579 to require all carbon dioxide pipelines to establish a monitoring and mitigation program to address corrosion-affecting constituents in the product stream; (15) amend § 195.55 to remove an existing, distance-based exception from the requirement to report safety-related conditions (SRCs) on carbon dioxide and other HVL pipelines, as well as introduce other clarifying and conforming revisions to part 195, subpart B reporting requirements relating to carbon dioxide pipelines; (16) introduce new requirements at § 195.210 for operators of all carbon dioxide pipelines to establish emergency planning zones extending two miles on either side of their pipelines that will inform operators' efforts in ensuring members of the public have adequate emergency response information; (17) propose miscellaneous revisions at parts 190, 196, and 198 consistent with the proposed definition of "carbon dioxide" at § 195.2; and (18) remove certain exclusions of hazardous liquid gathering pipelines from application of a handful of regulatory definitions at § 195.2 and emergency response and notification requirements at § 195.402, which were previously adopted to codify the results of judicial review of a recent

PHMSA rulemaking. In addition, PHMSA proposes conforming, administrative, or corrective changes at: §§ 195.3, 195.8, 195.18, 195.48, 195.49, 195.54, 195.61, 195.116, 195.120, 195.260, 195.262, 195.302, 195.401, 195.404, 195.406, 195.434, 195.436, 195.438, 195.450, and 195.588. PHMSA proposes an effective date (and, except as otherwise proposed for specific provisions, compliance date) for this rulemaking of 12 months following the publication of a final rule in the Federal Register. These 18 proposals are described in the paragraphs immediately below, and further detail is provided in Sections III and IV on all proposed amendments.

First, PHMSA proposes a series of amendments to statements of scope for part 195 and regulatory definitions to ensure more carbon dioxide pipelines are subject to meaningful safety and reporting requirements. Specifically, PHMSA proposes to amend the definition of carbon dioxide at § 195.2 to (1) include not only supercritical-phase carbon dioxide but also carbon dioxide in the gas and liquid phases, and (2) lower the threshold of carbon dioxide molecules present in the product stream (in any phase) necessary for a pipeline to be considered a "carbon dioxide" pipeline subject to part 195 to greater than 50 percent of the molecules in the product stream. PHMSA also proposes revising the definition of "highly volatile liquid or HVL" at § 195.2 to specify that all carbon dioxide pipelines (regardless of phase) are to be considered HVL pipelines. PHMSA also proposes several conforming additions to, and revisions of, miscellaneous definitions at § 195.2 to reflect the expansion of part 195 regulation to include gas-phase carbon dioxide pipelines and reflect other proposed amendments. Lastly, PHMSA proposes new exceptions to those listed at § 195.1 that would exclude certain long-term storage carbon dioxide facilities from part 195 and better align the PSR with statutory language bounding PHMSA's authority with respect to carbon dioxide pipelines.

Second, PHMSA proposes a series of amendments to its part 195 IM program regulations to strengthen requirements for all HVL pipelines. Pursuant to proposed amendments at § 195.452, operators of all HVL pipelines (including carbon dioxide pipelines) would need to perform vapor dispersion analyses in connection with their determinations of whether a release from their pipelines "could affect" an HCA and would therefore be subject to IM program requirements. Should an HVL pipeline operator determine that its pipeline could affect an HCA, it would be required to have fixed vapor detection and alarm systems and consider installation of EFRDs. PHMSA further proposes a new section § 195.456 prescribing the minimum elements—including operational (characteristics of the transported product stream) and environmental factors (terrain, typical weather conditions), frequency of analyses, and documentation requirements—for any vapor dispersion analyses performed for HVL pipelines under part 195. Section 195.456 would also provide HVL pipelines (as an alternative to performing a vapor dispersion analysis considering the factors listed in § 195.456(b)(1) through (7)) a simplified option of a standard 2-mile distance from either side of the pipeline when making their could-affect determinations. This proposal directly addresses findings from the Satartia accident.

Third, at § 195.402, PHMSA proposes that, in excavated trenches, operators of all part 195-regulated pipelines have instruments and tools capable of detecting hazardous concentrations of hazardous liquids, carbon dioxide, and any known deleterious constituents in the product stream. This NPRM would also require carbon dioxide pipeline operators to provide equipment, instruments, tools, and materials that might be used in the event of an emergency on a carbon dioxide pipeline to local emergency response organizations and train the same on their proper use. In addition, PHMSA proposes that operators of both hazardous liquid and carbon dioxide pipelines provide additional equipment in excavated trenches to protect personnel, including fire protection equipment and other devices capable of detecting hazardous conditions, as applicable. Lastly, PHMSA proposes an amendment at § 195.403(a)(4) to require operators of all part 195-regulated pipelines to train their response personnel on how to take actions to minimize the potential for asphyxiation.

Fourth, PHMSA proposes to require all operators of onshore carbon dioxide pipelines to communicate with affected entities (including, but not limited to, the general public) during an emergency on a carbon dioxide pipeline through a new paragraph § 195.402(e)(9).[6] This proposal builds on the existing framework of required public awareness programs, in accordance with § 195.440. Prior to an emergency, operators are required at § 195.440 to periodically communicate with the affected public, including providing information on: possible hazards associated with unintended releases from a hazardous liquid or carbon dioxide pipeline facility; indications that such a release may have occurred; steps that should be taken for public safety in the event of a hazardous liquid or carbon dioxide pipeline release; and procedures to report such an event. The new § 195.402(e)(9) would require all onshore carbon dioxide pipeline operators to make these communications with affected entities (including residents and occupants within an emergency planning zone) as soon as practicable during an emergency. Under the proposal, operators must continue to prioritize communications with emergency response organizations, comply with PHMSA notification requirements, and consult with applicable emergency response officials when determining communications content. The communication must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area. This proposal directly addresses

[6] This NPRM proposes to renumber the paragraphs following, not supplant them.

findings from the Satartia accident.

Fifth, PHMSA proposes modifications to § 195.111 to require enhanced design of carbon dioxide pipelines to mitigate fracture propagation through the pipe. This proposal would apply to carbon dioxide pipelines constructed, replaced, relocated, otherwise changed, or converted to part 195 service after the effective date of the final rule. The proposed modifications mirror those in the existing alternate maximum allowable operating pressure design requirements at § 192.112(b), updated for the current incorporated-by-reference version of American Petroleum Institute (API) Specification 5L (which standard PHMSA also proposes would be incorporated by reference at § 195.111). PHMSA proposes these detailed and prescriptive requirements to address the increased risk of brittle fracture propagation presented by carbon dioxide because of the rapid temperature drop possible upon change in phase or during a release, as well as the potentially significant adverse consequences from other fracture propagation mechanisms (e.g., running ductile fracture). This NPRM also proposes conforming changes at § 195.3 to reflect the incorporation of API Specification 5L at § 195.111.

Sixth, PHMSA proposes adding a new § 195.309 to part 195 subpart E to create a single, centralized section that contains the requirements for spike hydrostatic pressure testing for all part 195-regulated pipelines. PHMSA proposes the requirements for a spike hydrostatic pressure test in § 195.309 to be as follows: (1) water as the test medium; (2) a spike pressure of at least 150 percent of maximum operating pressure (MOP) or 100 percent of the pipe's specified minimum yield strength (SMYS), whichever is less; (3) the spike pressure is reached within the first 2 hours of the pressure test; (4) the spike pressure is held for at least 30 minutes; (5) the baseline pressure for the test is at least 125 percent of MOP; and (6) a total test duration of at least 8 continuous hours. In other sections of the PSR where spike hydrostatic pressure testing is required, PHMSA is proposing to introduce references to § 195.309.

Seventh, PHMSA proposes removing carbon dioxide from the list of acceptable test mediums for pressure tests conducted according to part 195 subpart E. In particular, PHMSA proposes removing carbon dioxide from the acceptable test mediums at § 195.306(c) for certain carbon dioxide pipelines meeting the criteria of that paragraph. The ability of operators of carbon dioxide pipelines to use inert gas (specifically excluding carbon dioxide, which PHMSA does not consider to be an inert gas) when pressure testing carbon dioxide pipelines, should they meet the requirements of § 195.306(c)(1) through (5), would remain unchanged.

Eighth, PHMSA proposes enhanced conversion to service requirements at § 195.5 for pipelines converted to part 195-regulated carbon dioxide and hazardous liquid service. Specifically, PHMSA proposes that operators of all pipelines converted to service under part 195 meet the design and construction requirements of subparts C and D. PHMSA also proposes certain enhanced requirements for pipelines being converted to part 195 carbon dioxide service. Prior to being placed into service, those pipelines must pass a spike hydrostatic pressure test in accordance with the proposed § 195.309. This NPRM also proposes at § 195.5 that operators perform certain assessments and evaluations on pipelines converted to carbon dioxide service either before or soon after service is initiated; namely, an in-line inspection within 12 months after the in-service date and close-interval and coating surveys within 15 months after the in-service date. These proposals will provide operators of pipelines converted to carbon dioxide service with crucial information on pipeline condition and integrity and require appropriate responses to indications of defects and anomalous conditions detected during these evaluations.

Ninth, PHMSA proposes enhanced right-of-way inspection requirements at § 195.412 for pipelines transporting hazardous liquids and carbon dioxide by adding specificity to the existing requirements in that section. This NPRM proposes that operators look for indicators of leakage from the pipeline, geologic hazards in the area that could affect the pipeline, nearby construction activity, areas of reduced depth of cover, and any other factors that may affect safety and operation during surface condition inspections of pipeline rights-of-way and adjacent areas. This proposal further states that, should an operator find indications of geologic hazards on or adjacent to the pipeline right-of-way, the operator would be required to perform additional inspections and evaluations; determine the extent of the geologic hazard(s) and the impact the hazard(s) may have on the pipeline; and take remedial action in accordance with § 195.401(b). Likewise, should operators find areas of depth of cover less than that required under § 195.248, the operator would be required to perform additional inspections and evaluations; determine the extent of the reduced depth of cover and the impact the reduced depth of cover may have on the pipeline; and take remedial action in accordance with § 195.401(b). Lastly, this NPRM proposes the addition of documentation and recordkeeping requirements for the life of the pipeline for those evaluations, determinations, and remedial actions taken in accordance with new paragraphs § 195.412(c) and (d). The proposals in this section would apply to all pipelines operating under part 195, including gathering lines, hazardous liquid pipelines, and carbon dioxide pipelines. These proposals directly address findings from the Satartia accident.

Tenth, PHMSA proposes an additional depth of cover classification for agricultural areas. Under this proposal, all part 195-regulated pipelines that are constructed, replaced, relocated, otherwise changed, or converted to service after the effective date of the final rule must be installed so that the cover between the top of the pipe and the ground level, roadbed, river bottom, or underwater natural bottom (as determined by recognized and generally accepted practices), as applicable, complies with a minimum depth of 48 inches (1,219 millimeters) for normal excavation in agricultural areas. Rock excavation would not be applicable for this location category.

Eleventh, this NPRM proposes leak detection systems be required for carbon dioxide pipelines at § 195.134. Further, if the pipeline is transporting supercritical- or liquid-phase carbon dioxide, PHMSA proposes this leak detection system must be a computational pipeline monitoring (CPM) leak detection system and meet the requirements of API Recommended Practice (RP) 1130, as required by §§ 195.134(c) and 195.444(c). PHMSA proposes that carbon dioxide pipelines existing on the effective date of any final rule would have four years from that effective date to implement these leak detection system requirements, and newly constructed pipelines would have one year from the effective date of a final rule. Conforming changes are also proposed at § 195.444 to reflect the proposals at § 195.134.

Twelfth, this NPRM proposes the addition of two new sections, §§ 195.263 and 195.429, to provide for the installation, operations, and maintenance of fixed vapor detection and alarm systems at specific facilities on certain pipelines transporting HVLs, including carbon dioxide. Specifically, PHMSA proposes that fixed vapor detection and alarm systems be required at each pump station, compressor station, meter station, and valve station (including facilities for launching and receiving in-line inspection tools or instrumented internal inspection devices) on HVL pipelines (including carbon dioxide pipelines) that are constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5 on or after the effective date of an eventual final rule. Under the proposal, these systems must be capable of: (1) monitoring transported products or constituents that might be deleterious to public safety or the environment; (2) continuous monitoring for concentrations approaching hazardous or flammable/explosive thresholds; (3) providing warnings and alarms to persons inside or near certain pipeline facilities; and (4) providing a notification to the operator's operational control center. At the proposed § 195.429, these fixed vapor detection and alarm systems must be tested at least once per calendar year, at intervals not exceeding 15 months, under conditions approximating actual operations. Testing must include the individual components of the system and the entire system as a whole, and the system must be maintained to function appropriately.

Thirteenth, PHMSA proposes the addition of carbon dioxide-specific risk factors for IM programs at § 195.452. Specifically, PHMSA proposes that operators consider deleterious constituents in the product stream when scheduling assessments, performing information analyses, and determining preventive and mitigative measures. These deleterious constituents can include hydrogen sulfide and water, among others. Additionally, PHMSA proposes modifying § 195.452(i)(4) to require carbon dioxide pipeline operators to install an EFRD if an operator determines that an EFRD is needed on a pipeline segment to protect an HCA in the event of a carbon dioxide pipeline release—a requirement already in place for hazardous liquid pipelines. This NPRM also proposes, at a new § 195.452(i)(5), that fixed vapor detection and alarm systems compliant with the proposed § 195.263 be required at each pump station, compressor station, meter station, and valve station (including facilities for launching and receiving in-line inspection tools or instrumented internal inspection devices) on existing HVL pipelines (including carbon dioxide pipelines) that are located in or could affect an HCA. Lastly, proposals in Appendix C to Part 195, "Guidance for Implementation of an Integrity Management Program," would clarify the appropriate safety risk indicator for carbon dioxide relative to other products in an operator's IM program.

Fourteenth, PHMSA proposes a monitoring and mitigation program at § 195.579 for constituents within carbon dioxide product streams that can affect corrosion, including microbes, water, oxygen, methane, hydrogen sulfide, carbon monoxide, sulfur oxides, and nitrous oxides. PHMSA proposes the program must include quality monitoring equipment at entry points to the pipeline (i.e., receipts); technology to mitigate those constituents and limit concentrations of water and hydrogen sulfide (i.e., separators and product sampling); quarterly evaluations to ensure effective management of those constituents; and an annual program review. For example, this NPRM proposes to limit the concentration of water vapor in carbon dioxide product streams to less than 50 parts per million (ppm) by volume, with no free water and limit hydrogen sulfide to less than 20 ppm by volume.

Fifteenth, PHMSA proposes several changes to its part 195, subpart B reporting requirements to enhance requirements pertinent to carbon dioxide pipelines. PHMSA proposes changes to § 195.55 to enhance reporting of SRCs on carbon dioxide and other HVL pipelines. Specifically, this NPRM proposes to remove the existing, distance-based reporting exception at § 195.55(b)(1) for SRCs on pipelines transporting HVLs, including carbon dioxide, as vapor clouds from HVL releases can travel in excess of the current distance requirement in that exception. PHMSA also proposes a series of other clarifying and conforming amendments to annual and accident reporting requirements to improve information collected from newly-regulated carbon dioxide pipelines, as well as clarify regulatory obligations for all carbon dioxide pipeline operators to submit National Pipeline Mapping System geospatial data.

Sixteenth, PHMSA proposes a new subparagraph (c) at the existing § 195.210 to improve public awareness and engagement on the potential public safety hazards associated with newly constructed, relocated, replaced, or otherwise changed (or newly converted to part 195 service) carbon dioxide pipelines within 2 miles of a residence, business, or place of public assembly. Specifically, this NPRM proposes to require that operators document decision-making when siting carbon dioxide pipelines near those locations, notwithstanding the requirement at § 195.210(a) for operators to avoid such locations as far as practicable. This NPRM also proposes that those operators would have to perform an initial population density survey within a 2-mile emergency planning zone on either side of the entire length of their pipeline and distribute emergency response information within that emergency planning zone before beginning operation. This proposal directly addresses findings from the Satartia accident.

Seventeenth, consistent with its proposed amendment of the § 195.2 definition of "carbon dioxide" to include lower-purity carbon dioxide product streams and different phases of carbon dioxide, PHMSA proposes miscellaneous revisions in parts 190 (emergency order procedures), 196 and 198 (damage prevention); as well as discussion of extension (without regulatory amendment) of requirements pertaining to assessment of annual operator user fees, part 195 subpart G personnel qualification requirements, and part 199 workplace drug and alcohol testing program requirements to newly-regulated carbon dioxide pipelines.

Finally (eighteenth), PHMSA proposes removing language excluding certain hazardous liquid gathering lines from application of certain regulatory definitions at §§ 195.2 and 195.417, as well as emergency planning, response, and notification requirements at § 195.402.

C. Costs and Benefits

Consistent with Executive Order (E.O.) 12866 ("Regulatory Review and Planning")[7] and the requirements of the Federal Pipeline Safety Laws (49 U.S.C. 60101 et seq.), PHMSA has

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[7] 58 FR 51375 (Oct. 4, 1993). E.O. 12866 was amended by E.O. 14094 ("Modernizing Regulatory Review"), 88 FR 21879 (Apr. 6, 2023).

prepared an assessment of the benefits and costs (to include relevant commercial benefits, public safety benefits, environmental benefits, compliance costs, and other risks) of this proposed rule, as well as reasonable alternatives. The estimated costs of this proposed rule stem from its proposed requirements for operators of supercritical-, gas-, and liquid-phase carbon dioxide pipelines and hazardous liquid pipelines to implement the requirements, as detailed in section III. The provisions include a range of proposals, primarily for carbon dioxide pipeline operators, along with some requirements that also apply to hazardous liquid pipeline operators, including gathering lines. PHMSA estimates the annualized costs of the NPRM to be approximately $21.3 million per year at a 2 percent discount rate.

As discussed throughout this NPRM and its supporting documents (including the PRIA and draft Environmental Assessment (DEA), each available in the docket for this NPRM), PHMSA expects the proposals to yield significant public safety benefits associated with reduced frequency and severity of accidents similar to that which occurred in 2020 on a supercritical-phase carbon dioxide pipeline near Satartia, Mississippi, although PHMSA did not quantify the expected benefits. The Satartia accident resulted in a number of adverse consequences (described in Section II.D of this NPRM), as well as more than $5 million in property damage, lost product, claims, other mitigation costs, and the social cost of released greenhouse gas emissions. PHMSA also expects the proposed rule will yield other, unquantified benefits, which include risk reduction for leaks and accidents on carbon dioxide and hazardous liquid pipelines; reduced consequences from all accidents and emergencies; improved enforcement and oversight; advanced safety measures and communications; avoided emissions; improved public confidence in the safety of carbon dioxide and hazardous liquid pipeline systems; and associated environmental enhancements for populations, including those in historically disadvantaged areas.[8] For the full analysis of costs and benefits (many of which are described qualitatively), please see the preliminary regulatory impact analysis (PRIA) in Docket No. PHMSA-2022-0125.

The regulatory amendments proposed are expected to improve public safety; reduce threats to the environment (including, but not limited to, reduction of pipeline leaks and accidents on gas- and liquid-phase carbon dioxide pipelines); and promote environmental justice. PHMSA expects that each of the proposed provisions would be technically feasible, reasonable, cost-effective, and practicable for the reasons stated in this NPRM and its supporting documents (including the PRIA and DEA), and because the commercial, public safety, and environmental benefits of those proposed regulatory amendments as described therein would outweigh any associated costs and support PHMSA's proposed rule compared to alternatives.

II. Background

A. Carbon Dioxide Properties

Carbon dioxide, or CO_2, is an odorless, colorless, and non-flammable gas at standard atmospheric temperature and pressure. Depending on the pressure and temperature, carbon dioxide may exist in the solid, liquid, gas, or supercritical phase, or some combination of the above.[9] Depending on the source, end-use application, and operating conditions, carbon dioxide may be transported by pipeline in the gas, liquid, or supercritical phases, or some combination of

[8] This proposed rulemaking may have certain equity benefits that are discussed further in section V.C., as well as in the PRIA and the DEA; however, PHMSA did not identify the presence or absence of equity benefits as determinative in considering the proposals herein.

[9] A *supercritical fluid* is a highly compressed fluid that exists at a temperature and pressure above its critical point, where distinct liquid and gas phases do not exist, but below the pressure required to compress it into a solid. The supercritical phase includes the dense vapor phase.

these phases.

Regardless of phase, exposure to carbon dioxide can entail public safety and environmental risks. When released from a pressurized system, carbon dioxide vaporizes immediately upon release.[10] Because carbon dioxide has a density 1.5 times that of air at standard temperature and pressure, released carbon dioxide vapor clouds can sink and displace oxygen before dissipating, potentially resulting in asphyxiation of human life. Asphyxiation can result in a range of adverse health consequences, ranging from the mild or transient (including light-headedness, nausea, headache, sweating, rapid breathing, increased heartbeat, shortness of breath, dizziness, mental depression, visual disturbances, or shaking) to more severe or permanent (short-term unconsciousness, permanent brain damage, or death), depending on the exposure duration and concentration. Hazardous levels generally start at approximately 7 percent carbon dioxide in the atmosphere, with more acute consequences at higher concentrations.[11] Animals are also susceptible to the consequences of carbon dioxide asphyxiation.

The asphyxiation hazards associated with carbon dioxide have prompted several Federal agencies to identify a variety of thresholds—usually expressed in terms of short-term and long-term exposure limits—to protect public safety, in particular focusing on personnel working in industrial settings. Examples of Federal thresholds include the following:

[10] Vitali M, Zuliani C, Corvaro F, Marchetti B, Terenzi A, Tallone F, "Risks and Safety of CO_2 Transport via Pipeline: A Review of Risk Analysis and Modeling Approaches for Accidental Releases," Energies, (2021); 14(15):4601, https://doi.org/10.3390/en14154601. In some circumstances, solid carbon dioxide formation is also possible upon release.
[11] Schettler, T, "Carbon Dioxide (CO_2) Normal Physiology & Hazards and Risks," Science and Environmental Health Network, (April 6, 2022). *https://www.sehn.org/sehn/2022/4/11/carbon-dioxide-fact-sheet*

- The Occupational Safety and Health Administration (OSHA) expresses the hazard of substances using a time-weighted average (TWA) approach, where a safe exposure limit is based upon the concentration of the substance over a given length of time. OSHA has set a TWA 8-hour exposure limit of 5,000 parts per million (ppm) for carbon dioxide.[12]
- The National Institute for Occupational Safety and Health (NIOSH) defines recommended exposure limits for both prolonged exposure (a TWA concentration for up to a 10-hour workday during a 40-hour workweek) and short-term exposure (a 15-minute TWA exposure that should not be exceeded at any time during a workday). NIOSH's recommended prolonged exposure limit for carbon dioxide is 5,000 ppm, and its recommended short-term exposure limit is 30,000 ppm. NIOSH also identifies a third threshold: concentrations at which a given chemical substance is immediately dangerous to life and health (IDLH) in that it is "likely to cause death or immediate or delayed permanent adverse health effects or prevent escape from such an environment" based on a 30-minute acute exposure. NIOSH has determined the IDLH for carbon dioxide is 40,000 ppm.[13]

PHMSA's PSR (discussed further in section II.C. below) contains safety standards

[12] OHSA, "OSHA Occupational Chemical Database: Carbon Dioxide," available at *https://www.osha.gov/chemicaldata/183* (last visited Sept. 8, 2023). NOAA, "Climate Change: Atmospheric Carbon Dioxide," available at *https://www.climate.gov/news-features/understanding-climate/climate-change-atmospheric-carbon-dioxide* (last visited Sept. 8, 2023). The concentration of carbon dioxide in air typically varies from location to location, between 300 and 600 ppm; the global average concentration of atmospheric carbon dioxide is about 418 ppm.

[13] NIOSH, "Pocket Guide to Chemical Hazards: Carbon Dioxide," available at https://www.cdc.gov/niosh/npg/npgd0103.html (last accessed Sept. 8, 2023).

directed toward mitigating risks to public safety and the environment arising from pipeline transportation of carbon dioxide. As with carbon dioxide transported by other modes of transportation, the principal risks to public safety and the environment associated with carbon dioxide pipeline transportation arise from the asphyxiation hazard in the event of a release. Pipeline transportation of carbon dioxide generally occurs at pressures well in excess (generally above 1,200 pounds per square inch, or psi) of standard, atmospheric pressure (14.7 psi), resulting in particularly severe hazards. Releases from pipelines operating under such high pressures, combined with the inherent properties of carbon dioxide (i.e., vapor pressure of carbon dioxide and the corresponding partial pressure of carbon dioxide in air), result in rapid de-pressurization and expansion, potentially creating odorless, invisible vapor cloud(s) of carbon dioxide that will generally displace oxygen within the area (due to the relative density of carbon dioxide as compared to air). Compounding this concern, simulated ruptures with identical characteristics (location, length, duration, etc.) on pipelines with identical operating parameters (pressure, temperature, etc.) indicate that a significantly larger percentage of the initial mass of carbon dioxide in the pipeline will be immediately released from a rupture on a carbon dioxide pipeline than the percentage of the initial mass of natural gas in the pipeline that would be released from a natural gas pipeline.[14] The released vapor cloud of carbon dioxide, which is larger (as a percentage of the initial amount of carbon dioxide in the pipeline) than a corresponding natural gas release, may not dissipate to safe levels quickly. In addition, the vapor cloud may travel a significant distance from the release location before enough dispersion into

[14] Mahgerefteh, Denton, & Rykov, "Pressurised CO_2 Pipeline Rupture," Institution of Chemical Engineers Symposium No. 154, (Jan. 2008).

the surrounding atmosphere occurs to reach a safe concentration. This risk is exacerbated in low-lying areas by the potential for settling (due to carbon dioxide's relatively high density). The above discussion corresponds with real-life conditions observed during a 2020 accident on a supercritical-phase carbon dioxide pipeline near Satartia, Mississippi (discussed in section II.D below).

In addition to the asphyxiation hazard, releases from carbon dioxide pipelines also entail other risks to public safety and the environment. Rapid de-pressurization of carbon dioxide upon release results in sharp, significant localized temperature drops, which compound pipeline integrity concerns by making the pipeline more prone to brittle fracture and creating additional hazards (e.g., frostbite) for emergency response and maintenance personnel. The initial force of the rupture itself can also create pressure waves that may present internal hemorrhaging hazards for operator personnel and the public and damage equipment in the immediate vicinity. Additionally, although much existing carbon dioxide pipeline infrastructure transports relatively high concentrations of naturally-occurring carbon dioxide,[15] the increasing interest in carbon dioxide pipeline infrastructure supporting carbon capture, utilization, and storage applications (discussed in section II.B below) is expected to involve pipeline transportation of carbon dioxide commodity streams containing a greater proportion of, or more diverse, hazardous constituents that (when released) would themselves pose significant public safety and environmental risks.[16]

The public safety and environmental risks of carbon dioxide pipelines described above

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[15] NETL, DOE/NETL-2014/1637, Subsurface Sources of CO_2 in the Continental United States: Volume 1, Discovered Reservoirs at Exhibit ES-3, (Mar. 2014).
[16] Det Norske Veritas (DNV), DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines at 17-18 (Sept. 2021).

are potentially amplified depending on their location. 2021 PHMSA annual report data notes that operators report approximately 10 percent of existing pipelines transporting supercritical-phase carbon dioxide as located in areas that could affect HCAs: areas defined by PHMSA regulations at § 195.450 as commercially navigable waterways or densely-populated urban areas and other populated areas.[17] However, this value could understate the existing carbon dioxide pipelines from which a release could in fact affect an HCA, given that some operators (including the operator involved in the 2020 Satartia accident discussed in section II.D below) have misidentified pipeline segments that could affect HCAs. PHMSA anticipates other carbon dioxide pipeline operators may be similarly understating the mileage of their pipeline systems that could affect HCAs; operators of hazardous liquid and other HVL pipelines (such as anhydrous ammonia, liquified petroleum gas, propane, butane, and ethane, among others) report approximately 40 percent of their pipelines are located in areas that could affect HCAs, and carbon dioxide pipeline transportation is not inherently more remote in nature than hazardous liquid and HVL pipeline transportation. Should new carbon dioxide pipelines be located disproportionately near communities with environmental justice concerns, those communities (many of whom have limited adaptive opportunities due to more limited economic opportunities and limited access to social and information resources) would be more likely to suffer acute

[17] A third category of HCAs specified in § 195.450—unusually sensitive areas—are, in accordance with § 195.6, applicable to hazardous liquid pipelines rather than carbon dioxide pipelines. Part 195 regulations have long distinguished between "carbon dioxide pipelines" and "hazardous liquid pipelines" based on the distinguishable risks to public safety and environment those commodities entail. However, that same regulatory distinction does not appear in other parts (e.g., parts 190, 198, 199) of PHMSA regulations; rather, those parts of PHMSA regulations generally align with the Pipeline Safety Laws characterization of carbon dioxide pipelines as a species of hazardous liquid pipeline facility. See 49 U.S.C. 60102(i)(1) directing PHMSA to regulate "carbon dioxide *transported by a hazardous liquid pipeline facility*") (emphasis added). As discussed further in section III.H below, among the proposals in this NPRM are a handful of amendments to improve conformity of approach across the PSRs.

adverse impacts of a pipeline failure. The addition of a new § 195.456 to provide explicit requirements for vapor dispersion analysis would reduce any risks disproportionately borne by those communities (see proposals under III.G.1 and IV of this NPRM for further details).

Releases from carbon dioxide pipelines also contribute to global public safety and environmental harms. Carbon dioxide is a particularly long-lived greenhouse gas (GHG) that can persist in the atmosphere for anywhere from 300 to 1,000 years and is the primary GHG produced by human activity contributing to global climate change; this in turn results in a multitude of adverse environmental and public safety harms, many of which are borne disproportionately by communities with environmental justice concerns in the United States and elsewhere.[18] Additionally, some of the carbon dioxide that neither disperses into the atmosphere nor is absorbed in biological processes may dissolve into the oceans and react with water to form carbonic acid, thereby contributing to ocean acidification, a process that disrupts marine food chains and human food supplies.[19]

Over the 10-year period from 2010 to 2021, 66 accidents on pipelines transporting supercritical-phase carbon dioxide have been reported to PHMSA.[20] In connection with these accidents predating the 2020 Satartia accident, operators reported to PHMSA no fatalities or injuries requiring hospitalization, and an average unintentional release of carbon dioxide to the

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[18] Buis, NASA, "The Atmosphere: Getting a Handle on Carbon Dioxide," (Oct. 9, 2019), *https://climate.nasa.gov/news/2915/the-atmosphere-getting-a-handle-on-carbon-dioxide/.* For an extended discussion of the various dimensions of environmental and public safety risks (including second-order risks to pipeline integrity) associated with anthropogenic climate change, see PHMSA, "Proposed Rule: Gas Pipeline Leak Detection and Repair," 88 FR 31890 at 31894-97 (May 18, 2023).

[19] NOAA, "Climate Change: Atmospheric Carbon Dioxide," available at *https://www.climate.gov/news-features/understanding-climate/climate-change-atmospheric-carbon-dioxide* (last visited Sept. 8, 2023).

[20] PHMSA annual report data indicates 4,560 miles of carbon dioxide pipeline were regulated in 2010 and 5,339 miles by 2021.

environment of approximately 920 barrels per accident (approximately 110 metric tons per accident).[21] This average release volume per accident does not include the 2020 Satartia accident, as the volume released during that accident was significantly higher than most other accidents over the same time ; its inclusion would skew the historical data. However, the relatively minor historical consequences are unlikely to be consistent with future experience. As explained further below in section II.D, the 2020 Satartia accident involved public safety and environmental harms significantly greater than the average historical accident on carbon dioxide pipelines. PHMSA expects development of a much more extensive carbon dioxide pipeline network that will result (absent the enhanced safety and reporting standards proposed) in an increased frequency of carbon dioxide pipeline accidents per mile (see the PRIA for further information). PHMSA also expects public safety and environmental consequences from those accidents to more closely resemble those experienced on the large-diameter carbon dioxide pipeline involved in the accident at Satartia, Mississippi than those of historical accidents on the nation's existing, limited carbon dioxide pipeline infrastructure.

According to operator-submitted accident reports on carbon dioxide pipelines since 1991,

[21] A longer lookback period yields a similar result: The history of data on reported carbon dioxide pipeline accidents yielded one injury and no fatalities, as reported by operators between 1991 and 2023. For accident reports made by pipeline operators, the operators determine the volume (in barrels) released from their pipeline based on the operating conditions of the pipeline at the time of the accident and the information known about the release. In the case of the average release volume from all accident reports from the 10-year period from 2010 to 2021, this volume is a sum of the individually reported volumes, all of which were based on the varied pipeline operating conditions during each reported accident, divided by the total number of accidents. The conversion from the reported 920 barrels per accident (5,165 ft^3) to approximately 110 metric tons per accident indicates an average density of 730 kg/m^3 (45.57 lb/ft^3) over the 66 reported accidents, which is within the range of densities for carbon dioxide in the supercritical phase.

the total volume of unintentionally released of carbon dioxide to the atmosphere amounts to 49,181 metric tons of carbon dioxide, which is roughly equivalent to driving a single motor vehicle for over 218.4 million miles (351.5 million kilometers), over 450 roundtrips to the moon, or continuously operating a natural gas-fired power plant for 48 days.[22] Notwithstanding the relatively small contribution to global carbon dioxide emissions that operating carbon dioxide pipelines may have, PHMSA intends for the proposals in this rulemaking to support further reductions in GHG emissions from carbon dioxide pipelines caused by leaks and accidents while minimizing the risk operating such pipelines presents to public safety.

B. Carbon Dioxide Pipeline Systems and CCUS

Existing carbon dioxide pipeline transportation in the United States is most commonly in the supercritical phase, as it can be transported more economically and efficiently in that phase due to its higher density and lower viscosity when compared to the transportation of carbon dioxide in other phases. To maintain the product in its supercritical phase, it is transported at temperatures above its critical temperature of 88 ºF (33 ºC) and (high) pressures ranging from 1,200 to 3,200 psi.[23] PHMSA annual report data from 2022[24] indicated that there are 5,514 reported miles of pipelines in the United States transporting supercritical-phase carbon dioxide. Pipeline transportation of carbon dioxide in other phases is not nearly as common; however,

[22] U.S. EPA, Greenhouse Gas Equivalencies Calculator, January 2024, https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator-revision-history#:~:text=Natural%20gas%2Dfired%20power%20plant,CO2%2Fpound%20of%20coal.

[23] Kuprewicz, R., "Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S.," (March 23, 2022).

[24] PHMSA, "Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data," *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.*

some pipelines currently in operation allow the temperature of the carbon dioxide to drop below the critical temperature (while remaining above the critical pressure) to maintain the product stream as a liquid.[25,26]

According to the Council on Environmental Quality,[27] there were 60 miles of gas-phase carbon dioxide pipelines in the United States in 2019. No information on the mileage of liquid-phase carbon dioxide pipelines is available. Pipelines transporting gas- (and potentially liquid-) phase carbon dioxide are typically limited to low-pressure applications, such as movement of carbon dioxide within an oil production field or the transportation of captured carbon dioxide from man-made sources (such as ethanol plants) to end use applications.

Historically, carbon dioxide's main value as a commodity has been in enhanced oil recovery (EOR), where it is injected through oil field wellheads and well piping and into a production formation to increase pressure and improve the rate of removal of produced hydrocarbons. Most carbon dioxide pipelines in the United States today are used in support of EOR, and generally connect naturally-occurring carbon dioxide reservoirs with production fields (although EOR operations are increasingly sourcing carbon dioxide captured from energy generation, industrial, and other applications).[28] As a result, most existing U.S. carbon dioxide pipelines are located close to large oil production fields, including in Wyoming, Colorado, New

[25] Congressional Research Service, "Carbon Capture and Sequestration (CCS) in the United States," (October 5, 2022). *https://sgp.fas.org/crs/misc/R44902.pdf*
[26] Peletiri et al, "CO_2 Pipeline Design: A Review" (August 21, 2018). *https://www.mdpi.com/1996-1073/11/9/2184*
[27] Council on Environmental Quality, "Report to Congress on Carbon Capture, Utilization, and Sequestration," (June 30, 2021). *https://whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf*
[28] National Petroleum Council, "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage," Chap. 6 - CO_2 Transport, at 6-1 and 6-3 (Mar. 2021). *https://dualchallenge.npc.org/.*

Mexico, Mississippi, Louisiana, Texas, Oklahoma, and North Dakota. The majority of carbon dioxide pipelines were built between 1980 and 2019, reflecting improvements in EOR technology. However, the high costs of sourcing and transporting carbon dioxide (among other policy and commercial drivers) have prompted increasing interest in capturing anthropogenic (human-made) sources of carbon dioxide for use in EOR applications. Carbon dioxide used in U.S. EOR operations in 2020 totaled about 1.6 billion cubic feet of carbon dioxide per day (Bcf/d), of which 1.3 Bcf/d (approximately 67,000 metric tons/day) came from naturally-occurring sources and 0.3 Bcf/d (approximately 16,000 metric tons/day) was captured from high-purity industrial sources, including ethanol plants.[29] PHMSA anticipates the strong commercial interest in carbon dioxide pipelines supporting EOR activities will continue in the near future (regardless of source), as discussed in the PRIA.

In addition to this historical, commodity-driven interest in carbon dioxide pipelines, there is increasing commercial and policy interest in increased carbon dioxide pipeline infrastructure from a process known as carbon capture, utilization, and storage (CCUS or CCS).[30] In CCUS, carbon dioxide is captured directly from emission sources (such as ethanol plants, electricity generation facilities, cement facilities or other industrial facilities) or indirectly from the atmosphere. Carbon dioxide is then transported for use, such as in industrial processes or as feedstock for useful commercial products such as building materials, or for sequestration, which

[29] National Academies of Sciences, Engineering, and Medicine, "Carbon Dioxide Utilization Markets and Infrastructure: Status and Opportunities: A First Report" at pp. 28 (2023). For a description of how carbon dioxide is used in EOR operations, see National Petroleum Council, "Meeting the Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage," Chap. 8 - CO2 Enhanced Oil Recovery (Mar. 2021).
[30] The Intergovernmental Panel on Climate Change, "Carbon Dioxide Capture and Storage," (2005), pp. 25, 33 (TS.5), 59, etc. *https://www.ipcc.ch/report/carbon-dioxide-capture-and-storage/*.

is the long-term storage of carbon dioxide (i.e., in underground spaces such as salt caverns or depleted hydrocarbon reservoirs). Commercial interest in CCUS can arise from diverse causes, including the following: commitments to reducing GHG emissions (including net-zero or carbon-neutral) or customer demands; pursuit of less expensive or more reliable sources of carbon dioxide to support industrial processes; conversion of what would otherwise be a waste product into a new revenue stream; or re-purposing of long-lived, stranded assets alongside clean energy alternatives. Government policy has also increased commercial interest in CCUS. By way of example, electricity generation (e.g., from coal and natural gas power plants) has historically been one of the largest sources of U.S. carbon dioxide emissions. Consequently, State governments have incentivized reduction of carbon emissions from the electricity generation sector via statute or by leveraging their States' public utility commissions' long-term integrated resource planning process to mandate reductions in carbon dioxide emissions from those utilities.[31] In response, many utilities have expressed interest in integrating CCUS within their systems. Similarly, some States have also established financial incentives (including, but not limited to, grants and pilot programs) encouraging utilities and other carbon dioxide emissions sources to pursue CCUS initiatives. Other economic sectors cite growing interest in exploring CCUS opportunities as a means of reducing their emissions footprint and generating new

[31] For a discussion of State initiatives either directly or indirectly promoting CCUS, as well as commitments made by electric utilities in response, see EPA, "Proposed Rule: New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 88 FR 33240 at 33263-64 (May 23, 2023).

revenue streams.[32]

Federal policy will support increased CCUS infrastructure in the coming years, including carbon dioxide pipeline transportation capacity.[33] In November 2021, a bipartisan Congressional coalition and the Biden-Harris Administration enacted the Infrastructure Investment and Jobs Act (Pub. L. 117-58, also called the "Bipartisan Infrastructure Law," or "BIL"), which contained a number of provisions directed toward expanding access to clean energy technologies. These provisions included the establishment of the Carbon Dioxide Transportation Infrastructure and Innovation Program to provide approximately $2.1 billion of low interest Federal loans and grants for building carbon dioxide transportation systems including pipelines, and future growth grants for transportation systems, including pipelines, that will fulfill currently uncontracted excess capacity to support integration of carbon capture and geologic storage. In total, the BIL established approximately $8.2 billion dollars through varied funding streams to accelerate CCUS technologies and deployment via loans, grants, regional hubs, technology award programs, and technology validation pilot projects.[34] The Inflation Reduction Act (Pub. L. 117-169), signed into law on August 16, 2022,[35] will also contribute to the expansion of carbon dioxide pipelines in the United States due to its enhancement of existing 45Q U.S. Federal tax

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[32] See, e.g., NETL, "Carbon Capture Interactive Project Map," available at *https://netl.doe.gov/carbon-management/carbon-capture/psc-map* (last visited Sept. 11, 2023); NETL, "Carbon Transport & Storage Interactive Product Map" available at *https://netl.doe.gov/carbon-management/carbon-storage/project-portfolio/technology-area-interactive-project-map* (last visited Sept. 11, 2023).
[33] Congressional Research Service, "CRS Insight: Carbon Dioxide (CO_2) Pipeline Development: Federal Initiatives," (June 6, 2023).
[34] Congressional Budget Office, "Carbon Capture and Storage in the United States," (December 2023), Chapter 2, Table 2-2, pp.16. *https://www.cbo.gov/system/files/2023-12/59345-carbon-capture-storage.pdf*
[35] Public Law 117-169, H.R. 5376, "Inflation Reduction Act of 2022," (August 16, 2022).

credits[36] previously enacted by the Bipartisan Budget Act of February 2018 (Pub. L. 115-123).[37] These 45Q credits are authorized for qualified carbon capture projects where construction begins prior to 2033, and, depending on the end use and source of the carbon dioxide, can provide up to $180 per metric ton of carbon dioxide.[38] These Federal incentives will encourage the near-term construction of new (or conversion of existing) pipelines to transport carbon dioxide between emission sources, direct air-capture facilities, end-use locations, and long-term storage facilities.[39]

As explained at greater length in the PRIA for this NPRM, it is difficult to predict what changes in the nation's carbon dioxide pipeline infrastructure will be brought about by CCUS, or the changes driven by State and local permitting requirements, stakeholder resistance, and macroeconomic and sector-specific market conditions. However, a significant expansion of the U.S. carbon dioxide pipeline network is expected.[40] By 2050, the mileage of carbon dioxide pipelines could grow (from the 5,514 miles of almost entirely supercritical-phase carbon dioxide pipelines in operation in 2022) to as much as 65,000 miles[41] of carbon dioxide pipelines to meet

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[36] *45Q* is a section of the tax code that provides incentives, in the form of tax credits, to encourage companies to invest in carbon capture and storage solutions that reduce carbon emissions to the atmosphere. The credit is codified at 26 U.S.C. 45Q.

[37] Public Law 115-123, H.R. 1892, "Bipartisan Budget Act of 2018," (February 9, 2018).

[38] Clean Air Task Force, "Carbon Capture Provisions in the Inflation Reduction Act of 2022," available at *https://cdn.catf.us/wp-content/uploads/2022/08/19102026/carbon-capture-provisions-ira.pdf* (last visited Sept. 11, 2023).

[39] Global CCS Institute, "The US Section 45Q Tax Credit for Carbon Oxide Sequestration: An Update," (April 2020). *https://www.globalccsinstitute.com/wp-content/uploads/2020/04/45Q_Brief_in_template_LLB.pdf.*

[40] National Academies of Sciences, Engineering, and Medicine (NAS), "Carbon Dioxide Utilization Markets and Infrastructure: Status and Opportunities: A First Report," (2023). *https://nap.nationalacademies.org/catalog/26703/carbon-dioxide-utilization-markets-and-infrastructure-status-and-opportunities-a*

[41] Council on Environmental Quality, "Report to Congress on Carbon Capture, Utilization, and Sequestration," (June 30, 2021), *https://whitehouse.gov/wp-content/uploads/2021/06/CEQ-CCUS-Permitting-Report.pdf.*

increased demand through 2050.

Demand for pipeline transportation of carbon dioxide for EOR applications is expected to continue, but CCUS will change the operating parameters and locations of pipeline transportation of carbon dioxide, which in turn will fundamentally alter the risk profile. Existing carbon dioxide pipelines generally link a limited universe of supply resources (often naturally occurring reservoirs of carbon dioxide) and demand sites to support EOR applications in oil production fields, whereas PHMSA expects CCUS infrastructure will be much more geographically diverse. Carbon dioxide sources for CCUS could be any point emissions source (e.g., an electric generation facility) located anywhere in the country; similarly, destinations for that captured carbon dioxide (i.e., long-term storage, EOR, or emerging, novel end-use applications) may be located a significant distance from the emissions source. Carbon dioxide pipelines (many of which will be larger in capacity and diameter to achieve economies of scale, or potentially located in the vicinity of HCAs) would be needed to link those far-flung source and end-use points in the emerging U.S. CCUS infrastructure.[42] PHMSA notes that some

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Princeton University, "Final Report: Net-Zero America Potential Pathways, Infrastructure, and Impacts," at pp. 220, (Oct. 2021), *https://netzeroamerica.princeton.edu/the-report*. PHMSA's projections in support of this rulemaking adopt a shorter time period (2024-2043) than the Princeton report. See PRIA at Sections 3.2.3 and Tables 3-6 to 3-9.

[42] NAS, "Carbon Dioxide Utilization Markets and Infrastructure: Status and Opportunities: A First Report," at pp. 82 (2023); Of the four announced, new carbon dioxide pipeline projects discussed in the PRIA (at Table 3-4), most are large-diameter, long-haul pipelines: Summit Carbon Solutions Pipeline (up to 24" in diameter, ca. 2000 miles long); Tallgrass Trailblazer (10" in diameter, ca. 400 miles); and ADM/Wolf Carbon Mt. Simon Hub Pipeline (up to 24" in diameter, ca. 300 miles). The PRIA also describes an additional, recently cancelled project (the Navigator Heartland Greenway) that was expected to be similar in diameter (up to 24" in diameter) and length (about 1,300 miles)). "Spur" pipelines, many of which may themselves be large in diameter and capacity, would be attached to these long-haul "trunk" pipelines connecting carbon dioxide sources and end-use/storage applications. Although the absence of precise information regarding the routes of either future "trunk" or "spur" carbon dioxide pipelines inhibits quantification of the amount of those pipelines that "could affect" an HCA (pursuant to § 195.452), projections of potential locations for CCUS infrastructure and carbon dioxide pipelines suggest an extensive national network that could involve closer proximity to HCAs. See, e.g., Princeton University, "Final Report: Net-Zero

pipeline companies have been operating long-distance and large-capacity carbon dioxide pipelines for decades, such as the Cortez 30-inch (762 mm) pipeline which was built in 1982 and carries 20 million tons of carbon dioxide per year.[43] However, many of these pipelines (2,191 miles, or nearly 41 percent of the total carbon dioxide pipeline mileage as of 2022) were built in the decade from 1980 to 1989, at a time when the U.S. population grew from 226 million to 248 million, compared to a population of 331 million in 2020.[44,45] The current projected expansion of carbon dioxide pipeline miles will be built in a much more populated environment generally, if not distinctly different locally, as these new pipelines will likely not serve traditional oil and gas production areas (i.e., generally more rural areas) for EOR purposes. CCUS infrastructure will also likely result in increased variety in the composition of the carbon dioxide product streams transported in those pipelines.[46] While the product streams in existing carbon dioxide pipelines tend to be high-purity, supercritical-phase carbon dioxide due to current sources (naturally occurring carbon dioxide reservoirs) and discrete end uses (EOR), CCUS infrastructure may involve pipeline transportation of carbon dioxide in different phases and at different operating temperatures and pressures. CCUS-supporting carbon dioxide pipelines could also be transporting carbon dioxide product streams with potentially very different chemical

America Potential Pathways, Infrastructure, and Impacts," at pp. 205-19 (Oct. 2021) and Great Plains Institute, "Transport Infrastructure for Carbon Capture and Storage," (June 2020).

[43] IPCC, "182 IPCC Special Report on Carbon dioxide Capture and Storage", section 4.2.2.3, pp. 182 (https://www.ipcc.ch/site/assets/uploads/2018/03/srccs_chapter4-1.pdf).

[44] PHMSA, "Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data," https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

[45] U.S. Census Bureau, Historical Population Change Data (1910 – 2020), https://www.census.gov/data/tables/time-series/dec/popchange-data-text.html (last accessed Aug. 19, 2024).

[46] NAS, "Carbon Dioxide Utilization Markets and Infrastructure: Status and Opportunities: A First Report," at pp. 78-79 (2023).

compositions than the high-purity carbon dioxide generally transported in existing pipelines.[47,48] By way of example, emissions captured from electric generation facilities may contain a variety of other constituents (such as water, oxygen, hydrogen sulfide, carbon monoxide, nitric oxide, nitrous dioxide, methane, amines, and glycol) that could themselves be corrosive for the pipeline or hazardous to public safety and the environment if released. The presence of these different constituents in the product stream increases the likelihood that internal corrosion will occur because there are more possible chemical mechanisms for internal corrosion, especially when water is present or there are significant changes in operating pressure (which can in turn affect the corrosivity of constituents in the product stream). Certain constituents (such as hydrogen sulfide, carbon monoxide, and methane) can also themselves represent hazards to public safety and the environment. Lastly, at least one carbon dioxide project for CCUS that is known to PHMSA involves the conversion of an existing natural gas pipeline (currently operating under part 192 regulations) to gas-phase carbon dioxide service. Conversions are often discussed within the industry and among policymakers as a potential approach for maintaining long-lived pipeline assets that could be stranded as utilities and industrial consumers convert from natural gas to renewable energy.[49]

C. Regulatory History

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[47] Porter RTJ, Fairweather M, Pourkashanian M, et al., "The range and level of impurities in CO_2 streams from different carbon capture sources," International Journal of Greenhouse Gas Control, 36. 161 – 174, (2015).
[48] Det Norske Veritas, "DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines," at pp. 17-18 (Sept. 2021).
[49] By way of example, Tallgrass has announced plans to convert its existing Trailblazer pipeline (a 10-inch diameter, 400-mile long, natural gas transmission pipeline) to gas-phase carbon dioxide service.

The House Committee on Energy and Commerce, in the 1987 session of the 100th Congress, noted the need for safety regulation and inspection of carbon dioxide pipelines due to the "unique potential for disaster if there were ever a break in a CO_2 pipeline."[50] In section 211 of the resulting Pipeline Safety Reauthorization Act of 1988,[51] Congress amended the Hazardous Liquid Pipeline Safety Act of 1979 (Pub. L. 96-129) to require the Research and Special Programs Administration (RSPA), PHMSA's predecessor agency, to issue regulations for carbon dioxide (without explicit limitation to a particular phase) transported by pipeline. In response, RSPA issued an NPRM in 1989 titled "Transportation of Carbon Dioxide by Pipeline."[52] In the 1989 NPRM, RSPA discussed a March 16, 1989, petition from API to amend part 195 to include carbon dioxide pipelines, rather than attempt to write a new part for carbon dioxide pipelines only. RSPA proposed changes to part 195 accordingly, including the addition of the definition of carbon dioxide to § 195.2. The 1989 NPRM proposed to regulate carbon dioxide in the supercritical phase only; the preamble noted that "transportation in the supercritical phase … is more desirable than transportation in the gaseous phase." This implies the lack of gas- and liquid-phase carbon dioxide pipelines at the time of the 1989 NPRM resulted in the regulation of supercritical-phase carbon dioxide only.

In 1991, RSPA issued the corresponding final rule (1991 final rule)[53] to the 1989 NPRM. The 1991 final rule discussed comments received on the 1989 NPRM from the Railroad Commission of Texas (TX-RRC), Exxon Corporation, API, the U.S. Department of the Interior

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[50] RSPA, 54 FR 41912, "Transportation of Carbon Dioxide by Pipeline," (October 12, 1989).
[51] Public Law 100-561, H.R.2266, "Pipeline Safety Reauthorization Act of 1988," (October 31, 1988).
[52] RSPA, 54 FR 41912, "Transportation of Carbon Dioxide by Pipeline," (October 12, 1989).
[53] RSPA, 56 FR 26922, "Transportation of Carbon Dioxide by Pipeline," (June 12, 1991).

(DOI), and the Public Utility Commission of Oregon. The main comments from all submissions included: corrections to the list of carbon dioxide pipelines in operation or under construction that RSPA noted in that NPRM; a suggestion to use cubic feet instead of barrels when completing reported volumes; suggestions to narrow the scope of various definitions; suggestions for exemptions related to line markers and valve spacing; and support for the proposals in the NPRM.

In their submission, the DOI noted that limiting the definition of carbon dioxide to the supercritical phase was "too limiting if the rule is to apply to all pipelines carrying CO_2." In response to this comment, RSPA stated in the 1991 final rule that while Section 211 of the Pipeline Safety Reauthorization Act of 1988 granted RSPA the authority to regulate all pipeline transportation of carbon dioxide, RSPA chose in the 1991 final rule to limit the regulations at part 195 to carbon dioxide in the supercritical phase only, due to economic factors that, at the time, resulted in supercritical-phase carbon dioxide as the main phase of carbon dioxide transported by pipeline. The 1991 final rule further stated that, if in the future, carbon dioxide is transported in phases other than the supercritical phase, RSPA would "issue additional regulations for such transportation."[54]

In their submission, Exxon Corporation requested RSPA consider narrowing the definition of carbon dioxide from a product stream consisting of "predominantly" carbon dioxide (over half of the product stream) to "a fluid consisting of more than 90 percent carbon dioxide molecules, compressed to a supercritical state." RSPA agreed and made changes to the 1991

[54] Proposed changes on this topic are contained within § 195.2, and further details can be found in sections III.A and IV of this NPRM.

final rule accordingly. Exxon Corporation stated in their comment that determining supercritical points on gas mixtures was difficult, and thus requested the 90 percent limit.[55]

The 1991 final rule also discussed the findings of the Technical Hazardous Liquid Pipeline Safety Standards Committee, also known as the Liquid Pipeline Advisory Committee (LPAC). On September 14, 1989, the LPAC voted unanimously that the NPRM and supporting documentation were technically feasible, reasonable, and practicable.

With the passage of the 2011 Pipeline Safety Act, Congress again amended the Hazardous Liquid Pipeline Safety Act of 1979 (by then recodified at 49 U.S.C. 60102(i)) and directed PHMSA to expand the existing PSR to include gas-phase carbon dioxide pipelines to supplement its then-existing authority to regulate pipeline transportation of liquid- and supercritical-phase carbon dioxide. Section 15 of the 2011 Pipeline Safety Act required PHMSA to issue regulations prescribing minimum safety standards for the transportation of gas-phase carbon dioxide by pipeline and consider if applying the standards in part 195 to gas-phase carbon dioxide pipelines would ensure safety.

In response to the 2011 Pipeline Safety Act, PHMSA published a report titled "Background for Regulating the Transportation of Carbon Dioxide in a Gaseous State" (2016 Report)[56] that discussed the various options for regulating gas-phase carbon dioxide pipelines, including applying part 195 standards. PHMSA issued a request for public comment on this report in the Federal Register on June 26, 2016.[57] PHMSA received seven comments on the 2016

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[55] Proposed changes on this topic are contained within § 195.2, and further details can be found in sections III.A and IV of this NPRM.
[56] https://www.regulations.gov/document/PHMSA-2016-0049-0001
[57] https://www.regulations.gov/docket/PHMSA-2016-0049

Report, including comments from Chapparal Energy, Denbury, API, the Texas Pipeline Association, and the National Institute of Standards and Technology.

Most of the comments from industry organizations and operators stated that if PHMSA deemed regulations on gas-phase carbon dioxide pipeline transportation were necessary, they would support the regulation of gas-phase carbon dioxide in part 195 rather than in part 192 or some combination of both parts 192 and 195.[58] Industry commenters supporting this stance noted that it would be onerous and difficult for operators to move back and forth between parts 192 and 195 if phase changes occurred in the pipeline during transport (whether routine or occasional), and all carbon dioxide pipelines at the time of the comment period were transporting supercritical-phase product (and thus were already regulated under part 195, if applicable). As noted by Chapparal Energy, "[h]aving all CO_2 pipeline regulations in a single Part eliminates the need for PHMSA regulations to define and otherwise distinguish between particular phases of CO_2 pipeline operations."

For the purposes of this NPRM, PHMSA agrees with this approach and the underlying points. Congress housed the statutory authority for PHMSA's regulation of gas-phase carbon dioxide within amendments to 49 U.S.C. 60102(i), which is implemented by PHMSA regulations in part 195. Including gas- and liquid-phase carbon dioxide within part 195 allows for unified regulations of carbon dioxide pipelines, regardless of phase. It reduces confusion for mixed-phase operations (i.e., gas and liquid, or liquid and supercritical), whether routine or occasional,

[58] A single commenter—a private citizen—recommended the use of part 192 to regulate gaseous carbon dioxide based on a misapprehension that PHMSA regulated pipeline transportation of liquid propane under part 192 of its regulations.

by locating these regulations in part 195. Parts 192 and 195 do not contain identical requirements, and thus requiring operators to comply with both part 192 and part 195 on mixed-phase pipelines, whether routine or occasional, would be onerous, and in some cases, impossible. Therefore, in this NPRM, all proposed amendments are located within part 195, including those requirements applicable to pipelines transporting carbon dioxide in the gas phase, with additional miscellaneous conforming changes to parts 190, 196, and 198. See section III.H for further details.

In addition to expanding the PSR to include gas-phase carbon dioxide pipelines, Section 15 of the 2011 Pipeline Safety Act underscored PHMSA's authority to regulate liquid-phase carbon dioxide pipelines under the PSR. Section 15 of the 2011 Pipeline Safety Act also clarified that any regulations PHMSA promulgates under this mandate shall exclude "piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation, or treatment of carbon dioxide or the preparation of carbon dioxide for transportation by pipeline at production, refining, or manufacturing facilities." Multiple comments from industry organizations and operators on the 2016 Report stated that PHMSA should not regulate EOR injection facilities (including wells) or production facilities. PHMSA agrees with this stance, which is consistent with the exclusionary statement in Section 15 of the 2011 Pipeline Safety Act and is reflected throughout the proposals of this NPRM.

Other industry comments on the 2016 Report noted the lack of gas- and liquid-phase carbon dioxide pipelines in operation and questioned the need for additional regulation. Another industry organization commenter requested PHMSA delay rulemaking on carbon dioxide pipelines until other proposed rules were finalized; the referenced rules have since been finalized in 2019 following this comment submission.[59] Other comments from State and Federal government agencies requested PHMSA consider the proximity of carbon dioxide pipelines to populated areas and consider limiting impurities in the carbon dioxide product stream.[60]

On May 31 and June 1, 2023, PHMSA held a public meeting in Des Moines, Iowa to discuss carbon dioxide pipeline safety and inform this rulemaking. During this meeting, members of the public, Tribal government representatives, Tribal advocacy representatives, State pipeline safety program representatives, pipeline safety advocacy groups, first responders and emergency response organizations, and industry experts provided information and feedback on a variety of topics, including: current regulations, public perspectives, research and development initiatives, dispersion modeling, and emergency response and preparedness. The meeting was well attended with about 1,100 total attendees in person and on the virtual webcast, with many opportunities for questions and public input. PHMSA also opened a docket in coordination with the public meeting to receive additional input during and in response to the meeting, which can be found at *https://www.regulations.gov/docket/PHMSA-2023-0013*. The full transcripts of the meeting can be found at: *https://primis.phmsa.dot.gov/meetings/MtgHome.mtg?mtg=165*.

D. 2020 Satartia Accident and Subsequent Response

Accident Investigation

On February 22, 2020, a 24-inch pipeline transporting supercritical-phase carbon dioxide failed approximately 1 mile southeast of Satartia, Mississippi. The rupture caused the release of

[59] 84 FR 52180, PHMSA, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," (October 1, 2019).
[60] See section IV for more details on how PHMSA has addressed these concerns in the proposed regulatory text.

more than 31,000 barrels of supercritical-phase carbon dioxide that vaporized at atmospheric conditions. The pipeline failed on an embankment that had subsided adjacent to a local highway. Heavy rains triggered a landslide, which created axial strain on the pipeline and resulted in a full circumferential girth weld failure, revealing both brittle and ductile fracture.[61] Risks to pipelines caused by ground movement forces such as landslides are considered to be part of a larger class of threats known as geologic hazards.[62]

In response to this accident, PHMSA conducted an accident investigation. On May 26, 2022, PHMSA published its failure investigation report,[63] which discussed the accident cause and contributing factors. PHMSA's investigation of the accident yielded the following:

1. The operator's operations and maintenance procedures pursuant to § 195.401 did not address the potential for pipeline damage due to soil instability, despite the prevalence of soil instability in the region. The operator's personnel had been aware the area had a high potential for, and in fact frequently experienced, ground movement due to non-cohesive soils and significant rainfall recorded in recent years.
2. The operator's IM program pursuant to § 195.452 did not address threat identification and/or assessment for geologic hazards, or corresponding preventative or mitigative measures for geologic hazards. The operator's IM plan had identified "geo-technical

[61] A brittle fracture is a breakage or cracking of a material without significant deformation before failure. A ductile fracture is a breakage or cracking with significant plastic deformation of the material before fracture.
[62] Proposed changes on this topic are located at § 195.412, and further details can be found in sections III.D.1 and IV of this NPRM.
[63] PHMSA, Failure Investigation Report, "Denbury Gulf Coast Pipelines, LLC, February 22, 2020" (May 26, 2022). *https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf*

hazards" as a risk to pipeline integrity, but the operator had neither evaluated those hazards in a risk analysis, nor provided details regarding hazard prevention and mitigation.

3. The operator's aerial patrols performed pursuant to § 195.412 requirements to inspect pipeline rights-of-way did not identify a geologic hazard at the failure location prior to the accident.

4. The operator's carbon dioxide vapor dispersion model significantly underestimated the potential area that could be impacted by a release. Prior to the accident, the operator had used a third-party vapor dispersion model to determine the areas around the pipeline that could be affected by a pipeline release. That model—performed nearly a decade (in 2011) before the accident and based on an airborne concentration limit (30,000 ppm) well below NIOSH's 40,000 ppm IDLH threshold—significantly underestimated the area that could be affected. The operator had not supplemented that vapor dispersion modeling with an overland spread analysis. As a result, the operator did not identify in its § 195.452 IM program the ruptured pipeline segment as a pipeline segment that could affect an HCA (namely, Satartia, Mississippi). In addition, the operator did not include Satartia in its § 195.440 public awareness plan. In the hours after the accident, local emergency responders used a plume model generated by the National Weather Service when deciding to evacuate Satartia after determining the released carbon dioxide would move directly toward the town. Air sampling conducted in Satartia (roughly a mile from the accident), which began roughly three hours following the accident and ended the next day, showed outdoor carbon dioxide concentrations as high as 26,000 ppm and indoor concentrations as high as 28,000 ppm.

5. The operator did not notify local emergency responders of a potential failure. Before the accident, the operator had neither adequately coordinated with local emergency response officials on potential response efforts in the event of a release, nor developed and implemented an adequate continuing public education program. Several regulations relate to liaison with emergency responders, including §§ 195.402, 195.408, and 195.440.
6. The failure investigation report detailed the adverse impact of those omissions on the emergency response activities conducted after the pipeline ruptured at 7:06 p.m. on February 22, 2020. Though the operator was aware of a potential accident at 7:07 p.m. through alarms received at its control center, it did not contact fire, police, or any other local emergency responders. Instead, local emergency responders contacted the operator about 42 minutes after the rupture to notify the operator of the release and gain information on the released product. Local emergency responders were forced to respond to an unknown threat with limited information from calls from the public upon which to base their actions. Operator personnel who informed the National Response Center of the accident (two hours after the rupture) characterized the release as involving only approximately 220 barrels of carbon dioxide.

Enforcement

As a result of the accident investigation, PHMSA issued a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (NOPV)[64] to the operator on May 26,

[64] PHMSA, CPF 4-2022-017-NOPV, "Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order to Denbury Gulf Coast Pipeline, LLC," (May 26, 2022).

2022. On March 24, 2023, PHMSA and the operator resolved the matter by entering into a consent agreement[65] that assessed a civil penalty of $2,868,100 and required the operator to perform a number of actions, including:

- Update its geologic hazard program to address hazards on all of its pipelines as well as include preventative and mitigative measures to enhance public safety and the safe operation of its pipeline system. The geologic hazard program must include substantive information regarding hazard identification on each pipeline, assessment, remediation, and hazard recognition training for employees responsible for identifying geologic hazard issues.
- Complete a review of its written procedure on patrolling and leak detection, and based on that review, include within that procedure additional guidance for the identification of potential geologic hazard sites and the training of personnel on the amended procedure.
- Update its dispersion model and buffer zone assessment by employing a model that considers the characteristics of carbon dioxide and the effects of the specific terrain surrounding the pipeline involved in the accident, including effects of both elevation changes and channeling, upon the release of carbon dioxide to the atmosphere.
- Assess the extent and coverage of potential vapor cloud releases by updating its

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https://primis.phmsa.dot.gov/comm/reports/enforce/documents/42022017NOPV/42022017NOPV_PCO%20PCP_0526022_(20-176125).pdf

[65] PHMSA, CPF No. 4-2022-017-NOPV, "Consent Order and Agreement with Denbury Gulf Coast Pipeline, LLC" (Mar. 24, 2023). *https://primis.phmsa.dot.gov/comm/reports/enforce/documents/42022017NOPV/42022017NOPV_Consent%20Agreement%20and%20Order_03242023_(20-176125).pdf*

dispersion model to allow for variable inputs relating to foreseeable weather and pipeline operating conditions.

- Incorporate newly identified HCAs or could affect HCA pipeline segments in its IM and public awareness programs and conduct a baseline assessment.
- Conduct a risk analysis and identify additional preventive and mitigative measures to enhance public safety or environmental protection for all HCAs or could affect HCA pipeline segments.
- Identify all Federal, State, and local government organizations that may respond to a pipeline emergency that were not previously identified and included within the operator's public awareness program and ensure they are now included in that program.

Advisory Bulletin

On June 2, 2022, PHMSA issued an advisory bulletin (ADB-2022-01)[66] to urge owners and operators of pipeline systems to conduct a comprehensive review of their systems for the possibility of a failure due to geologic hazards. ADB-2022-01 is an updated version of a previously issued advisory bulletin on geologic hazards (ADB-2019-02)[67] issued on May 2, 2019. PHMSA issued this updated advisory bulletin in part as a response to the Satartia rupture. ADB-2022-01 reminded owners and operators of gas and hazardous liquid pipelines, including

[66] PHMSA, 87 FR 33576, ADB-2022-01, "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards," (June 2, 2022).
[67] PHMSA, 84 FR 18919, ADB-2019-02, "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards," (May 2, 2019).

those transporting carbon dioxide, about the serious safety-related issues that can result from earth movement and other geologic hazards, including changing weather patterns due to climate change. PHMSA requested pipeline operators consider several actions to ensure pipeline safety from earth movement and other geologic hazards, including identifying areas prone to large earth movements; developing design, construction, and monitoring plans and procedures to address site-specific hazards for each identified area; monitoring changing weather patterns and environmental conditions in proximity to their pipelines; using available data and information resources to assess facility vulnerability; and basing mitigation measures on site-specific conditions.

E. State-Level Carbon Dioxide Pipeline Efforts

As discussed further below in section V.I, under certain circumstances, the Pipeline Safety Laws (at 49 U.S.C. 60104(c)) recognize States' authority to promulgate safety (e.g., design, testing, operations, and maintenance) and reporting regulations[68] governing intrastate pipelines within their borders. The same law prohibits a State authority from adopting safety standards for interstate pipelines. Reviews of State statutory and regulatory frameworks for intrastate carbon dioxide pipelines indicate that only a handful of States have issued statutory or regulatory safety and reporting requirements specific to intrastate carbon dioxide pipelines in any phase.[69] Most States (if their statutory and legislative safety frameworks for intrastate pipeline

[68] For the purposes of this rulemaking, PHMSA may refer to safety standards and reporting regulations separately, but this does not mean reporting regulations may not also be safety standards.
[69] Lockman, "Permitting CO_2 Pipelines: Assessing the Landscape of Federal and State Regulations" at iii-v, pp. 10-12 and 48-49 (Sept. 2023); National Association of Regulatory Utility Commissioners, "Onshore U.S. Carbon

address carbon dioxide pipelines at all) generally reference PHMSA's part 195 reporting and safety requirements with minimal enhancement. [70] These requirements, as explained at greater length in section III below, are limited in scope to pipeline transportation of high-purity, supercritical-phase carbon dioxide. Some States have also shown comparatively greater interest in exercising their inherent siting and eminent domain powers to ensure the safe operation of pipelines transporting carbon dioxide passing through their borders. On a case-by-case basis, States may attempt to leverage that authority to extract from specific project sponsors voluntary commitments exceeding pertinent PHMSA and State pipeline safety requirements.[71]

The above considerations of State regulatory authority, and diverse approaches employed in exercising those authorities, risk creating a patchwork of regulatory requirements that could frustrate efforts to address the public safety and environmental risks of carbon dioxide pipelines (discussed throughout section II) and magnify any impacts associated with those risks. A spectrum of stakeholders, including environmental groups, academia, and State regulators, have

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Pipeline Deployment: Siting, Safety, and Regulation," (June 2023); National Association of Pipeline Safety Representatives, "Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels compared to Code of Federal Regulations," (2022); Mack & Munoz-Patchen, "CO_2 Pipeline infrastructure for Sequestration Projects" 17:1 Texas J. Oil, Gas, and Energy Law 101 (2022); Nordhaus & Pitlick, "Carbon Dioxide Pipeline Regulation," 30:1 Energy Law J. 85 (2009).

[70] PHMSA acknowledges exceptions to this generalization. A few States with relatively extensive, existing carbon dioxide pipeline infrastructure (e.g., Texas) have carbon dioxide-specific pipeline regulations (16 Tex. Admin Code § 8.1 et seq.). Meanwhile, other states (California and Illinois) have codified moratoriums on carbon dioxide pipeline development and are exploring enhanced safety regulations for intrastate pipelines. California Natural Resources Agency, "Proposal to the Legislature for Establishing a Framework and Standards for Intrastate Pipelines Transporting Carbon Dioxide" at pp. 2,6, (Mar. 2023); Illinois Gen. Assembly, "Safety Moratorium on Carbon Dioxide Pipelines Act," SB1916, 103rd Gen. Assembly (July 2024).

[71] See, e.g., Navigator Heartland Greenway, Docket No. HP-22-020 (In re Navigator Heartland Greenway Construction Permit Application), "Application of Navigator Heartland Greenway LLC, for a Permit Under The South Dakota Energy Conversion and Transmission Facilities Act to Construct the Heartland Greenway Pipeline in South Dakota" at Exhibit D (Sept. 27, 2022) (committing to a number of enhanced design, construction, operation, maintenance, and corrosion control protocols exceeding current PHMSA requirements).

underscored the value of enhanced Federal reporting and safety requirements to ensure that the anticipated expansion of carbon dioxide pipeline infrastructure occurs in a manner ensuring the adequate protection of public safety and the environment.[72]

III. Proposed Amendments

A. Updated Title, Applicability, and Definitions—Part 195 Title and §§ 195.1 and 195.2

1. Revised Part 195 Title

The title of part 195 currently reads as "Transportation of Hazardous Liquids by Pipeline" and has undergone several changes since the first regulations for "carriers by pipeline" were contemplated under part 80.[73] When RSPA proposed amendments to part 195 to include regulations for the transportation of carbon dioxide in 1989, RSPA noted that API suggested that the title be changed to "Transportation of Hazardous Liquids and Carbon Dioxide by Pipeline." At that time, RSPA believed that the change would result in an awkward title and further supported the decision to not include carbon dioxide in the title by stating that "Congress did not see fit to change the title of the statute which authorizes the regulation of CO_2 pipelines." PHMSA now understands that, given the additional statutory authority provided by Congress in the 2011 Pipeline Safety Act and the anticipated increase in pipeline facilities used to transport

[72] See, e.g., "Letter to Secretary Buttigieg from a Coalition of Groups Calling for Enhanced Federal Carbon Dioxide Pipelines Regulations" (May 1, 2023) (memorializing a request submitted by the Pipeline Safety Trust, Natural Resources Defense Council, Environmental Defense Fund, Earthjustice, Sierra Club, and the Bold Alliance); Lockman, "Permitting CO_2 Pipelines: Assessing the Landscape of Federal and State Regulations" at pp. 48-49 (Sept. 2023); NAS, "Carbon Dioxide Utilization Markets and Infrastructure: Status and Opportunities: A First Report" at pp. 100, 125 (2023); NARUC, Onshore U.S. Carbon Pipeline Deployment: Siting, Safety, and Regulation at pp. 30-31 (June 2023).
[73] 32 FR 1098 (*https://www.govinfo.gov/content/pkg/FR-1967-01-31/pdf/FR-1967-01-31.pdf*)

carbon dioxide in the gas, liquid, and supercritical phases, it is now appropriate to modify the title of part 195 to be "Transportation of Hazardous Liquids and Carbon Dioxide by Pipeline." Including carbon dioxide in the title of part 195 will provide operators of carbon dioxide pipelines clear direction of which part to follow when applying the PSR to their operations.

2. Revised Applicability—§ 195.1

When RSPA issued its 1991 final rule[74] bringing supercritical-phase carbon dioxide pipelines within the scope of part 195, carbon dioxide pipelines were generally limited to use in EOR production operations. The 1991 final rule extended several existing regulatory exceptions from PHMSA jurisdiction over hazardous liquid pipelines at § 195.1(b) to the transportation of carbon dioxide, consistent with the statutory definition of "transportation of hazardous liquid" codified at 49 U.S.C. 60101(a)(22).[75,76] In later rulemakings, PHMSA added two additional exceptions—currently at §§ 195.1(b)(6) and (7)—clarifying application of the exceptions to pipelines introduced in 1991 to account for the DOI's adjacent jurisdiction over pipelines on the Outer Continental Shelf.[77] Meanwhile, the 2011 Pipeline Safety Act incorporated a new statutory exception specific to carbon dioxide (codified at 49 U.S.C. 60102(i)(3)) clarifying application of

[70] RSPA, 56 FR 26922, "Transportation of Carbon Dioxide by Pipeline," (June 12, 1991).
[75] 49 U.S.C. 60101(a)(22)(B): ("'transporting hazardous liquid' . . . (B) does not include moving hazardous liquid through (i) gathering lines in a rural area; (ii) onshore production, refining, or manufacturing facilities; or (iii) storage or in-plant piping systems associated with onshore production, refining, or manufacturing facilities[.]").
[76] 56 FR 26921 (June 12, 1991). Specifically, §§ 195.1(b)(5), (6), (7), and (8) were added in 1991. In 1997, a new subparagraph (b)(6) was added, resulting in redesignation of the previous (b)(6) as (b)(7) and the previous (b)(7) as (b)(8); see 62 FR 61692 (Nov. 19, 1997). In 2003, RSPA adopted amendments to (b)(5) and (b)(6), as well as a new subparagraph (b)(7); however, because of a clerical error, integration of those amendments and redesignation of existing subparagraphs (b)(7), (b)(8), and (b)(9) within the CFR did not occur immediately. See 68 FR 46109 (Aug. 5, 2003). In 2008 (73 FR 31634 (July 3, 2008)), those earlier amendments were fully integrated into § 195.1(b), resulting in the current organization of § 195.1(b) subparagraphs.
[77] 73 FR 31634, PHMSA, "Pipeline Safety: Protecting Unusually Sensitive Areas from Rural Onshore Hazardous Liquid Gathering Lines and Low-Stress Lines," (June 3, 2008).

the longstanding statutory exception at 49 U.S.C. 60101(a)(22) and its implementing regulatory exception at § 195.1(b) to certain carbon dioxide piping and equipment.[78]

PHMSA now proposes to revise the exception at § 195.1(b)(8) to relocate language in that section related to carbon dioxide within a new subparagraph § 195.1(b)(11). That new subparagraph § 195.1(b)(11) would also codify in the PSR the limitation on statutory construction prescribed by Congress in the 2011 Pipeline Safety Act. Specifically, PHMSA proposes to codify at § 195.1(b)(11) language from 49 U.S.C. 60102(i)(3) establishing that part 195 does not apply to piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation, or treatment of carbon dioxide or the preparation of carbon dioxide for transportation by pipeline at production, refining, or manufacturing facilities. The new subparagraph § 195.1(b)(11) would also include an applicability limitation relocated from § 195.1(b)(8) that certain devices and associated piping necessary to control pressure in the downstream carbon dioxide pipeline at § 195.406(b) are not applicable to this exception and therefore covered by part 195. PHMSA recognizes that exceptions in other subparagraphs at § 195.1(b) would continue to apply to carbon dioxide because they are location- or context-specific and would not conflict with the statutory limitations on PHMSA jurisdiction at 49 U.S.C. 60101(a)(22) and 60102(i)(3). Accordingly, PHMSA does not propose to modify those other exceptions applicable to carbon dioxide at § 195.1(b)(5), (b)(6), and (b)(9). Accordingly, PHMSA does not propose to modify those other exceptions applicable to carbon dioxide at §

[78] 49 U.S.C. 60102(i)(3) ("Limitation on statutory construction. Nothing in this subsection authorizes the Secretary to regulate piping or equipment used in the production, extraction, recovery, lifting, stabilization, separation, or treatment of carbon dioxide or the preparation of carbon dioxide for transportation by pipeline at production, refining, or manufacturing facilities.").

195.1(b)(5), (b)(6), and (b)(9).As described in section II.B above, concern regarding the contributions of carbon dioxide to climate change has accelerated Federal, State, and commercial interest in the development of novel uses for carbon dioxide, as well as the buildout of CCUS facilities—including long-term carbon dioxide storage facilities, such as depleted production fields and geologic formations. Although PHMSA understands that there is no explicit statutory prohibition barring the Agency from regulating the storage of carbon dioxide in long-term underground storage facilities under part 195, which are expected to be integral components of an emerging interstate carbon dioxide pipeline transportation network,[79] several considerations support PHMSA not regulating such facilities under part 195 at this time. Not regulating long-term carbon dioxide storage facilities at this time conserves the limited personnel resources of PHMSA and its State partners at the same time this NPRM proposes to expand the carbon dioxide pipelines subject to part 195 regulations; notably the mileage of regulated carbon dioxide pipelines will further increase as the nation's CCUS infrastructure expands. Moreover, long-term underground carbon dioxide storage facilities are already subject to regulatory oversight by other authorities. For example, long-term, geologic sequestration facilities and the fluids that are injected into them are regulated by the U.S. Environmental Protection Agency (EPA), which regulates underground injection through its Underground Injection Control (UIC) program, the Greenhouse Gas Reporting Program (GHGRP) and associated regulations, as well as other

[79] Some of those long-term storage facilities could be designed to accommodate removal of stored carbon dioxide for later re-introduction into the National pipeline network.

regulatory authorities.[80] While the EPA establishes minimum standards and criteria for UIC programs, most States are responsible for regulating and permitting wells designated as Class I through V, including Class II recovery wells, of which, some are used for injecting carbon dioxide for EOR.[81,82,83] In 2010, the EPA added Class VI wells to the UIC program specifically to regulate the underground injection of carbon dioxide for geologic sequestration.[84] PHMSA therefore proposes to add an additional exception at § 195.1(b)(10)(iii) to indicate that this rule will not apply part 195 regulations to "the outlet of the pipeline isolation valve located at the wellhead of an injection well used for long-term carbon dioxide storage."[85] PHMSA advises operators to review the definitions of "underground injection," "well," and "well injection," defined by the EPA at 40 CFR 144.3, when applying the exceptions related to carbon dioxide at § 195.1(b), as PHMSA intends to apply the same meaning.

3. Revised and New Definitions—§ 195.2

Carbon Dioxide—Phase

RSPA's 1991 final rule extending part 195 safety standards and reporting requirements to

[80] Congress recently granted the U.S. Department of Interior the authority to issue leases for carbon sequestration on the Outer Continental Shelf and promulgate regulations to carry out this authority. The EPA does not regulate carbon sequestration facilities or wells on the Outer Continental Shelf.
[81] Carbon Capture and Sequestration (CCS) in the United States, Congressional Research Service, October 5, 2022 (*https://sgp.fas.org/crs/misc/R44902.pdf*) at pp. 2
[82] https://www.epa.gov/uic/underground-injection-control-well-classes
[83] In general, Class II wells are used to inject brines, CO_2, steam and other fluids associated with oil and gas productions, as well as liquid hydrocarbons for storage. (George Peridas, Lawrence Livermore National Laboratory, Permitting Carbon Capture & Storage Projects in California, February 2021, LLNL-TR-817425)
[84] Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells (75 FR 77230, December 10, 2010), codified at 40 CFR 146.81 et seq.
[85] PHMSA notes that the terms "upstream" and "downstream" when used at § 195.1(b)(10)(i) and (ii) are to be taken literally and not oriented toward the industry meaning of "upstream, midstream, and downstream." "Upstream" is taken to mean away from the injection operation and toward wherever the carbon dioxide is being produced. Likewise, "downstream" is taken to mean toward the injection operation, or downhole.

carbon dioxide pipeline facilities limited those requirements to carbon dioxide in the supercritical phase, rather than the liquid and gas phases. RSPA explained that pipeline transportation of supercritical-phase carbon dioxide was more efficient than pipeline transportation of gas-phase carbon dioxide, as the latter would demand more energy to transport (in the form of large compressors rather than small pumps) and lower operating pressures than supercritical-phase carbon dioxide pipelines. RSPA implicitly dismissed the feasibility of pipeline transportation of liquid-phase carbon dioxide when discussing how the physical properties of carbon dioxide complicate its transportation in liquid form.[86] RSPA explained that it could, as warranted, exercise its statutory authority to regulate pipeline transportation of carbon dioxide in other phases within future rulemakings.

As discussed in section II.C above, Congress in the 2011 Pipeline Safety Act directed PHMSA to issue regulations imposing safety and reporting requirements on gas-phase carbon dioxide pipelines. In addition, concern regarding the contributions of carbon dioxide to anthropogenic climate change has buoyed interest in pipeline transportation of carbon dioxide to support novel end uses of carbon dioxide and buildout of carbon capture and long-term storage facilities, including sequestration facilities. Such transportation may involve not only pipeline transportation of carbon dioxide not in the supercritical phase. In addition, there is significant commercial interest in re-purposing existing natural gas pipelines to carbon dioxide service. Converted pipelines may have been designed for lower MOPs more appropriate for gas-phase

[86] 56 FR 26922.

carbon dioxide service than supercritical-phase carbon dioxide service.[87] The rapidly evolving uses of and system configurations for carbon dioxide capture, pipeline, and long-term storage facilities, including sequestration facilities, are expected to support demand for more carbon dioxide pipelines, including those transporting carbon dioxide in the gas phase, and possibly also in the liquid phase. As explained above in section II.E, that anticipated increase in commercial interest in gas- and liquid-phase pipeline transportation will occur largely within a regulatory gap; just as PHMSA regulations do not explicitly address gas- and liquid-phase carbon dioxide pipelines, most State regulatory schemes are silent regarding those carbon dioxide pipelines.[88]

These fast-evolving market dynamics highlight the importance of PHMSA's proposed amendment at § 195.2 to expand the definition of "carbon dioxide" and thereby ensure that pipeline transportation of carbon dioxide in any phase, including the gas and liquid phases, occurs in a manner that protects public safety and the environment. As discussed throughout the applicable portions of sections III and IV of this NPRM, PHMSA is not proposing the haphazard extension of part 195 requirements to gas- and liquid-phase carbon dioxide pipeline facilities. Instead, PHMSA has reviewed the entirety of part 195 and proposes to supplement or modify

[87] "CO_2 Pipelines Design: A Review" Peletiri et al (2018) ("Generally, transporting gaseous CO_2 in pipelines is not economical due to the high volume of the gas, low density and high-pressure losses. It may however, still be more cost effective to transport CO_2 in the gaseous state than in the liquid or supercritical states under certain circumstances."). Pipelines converted from natural gas to carbon dioxide service will be unlikely to operate at the high pressures required to maintain the supercritical phase (over 1,200 psi), and thus will be primarily used for gas-phase carbon dioxide.

[88] See generally: National Association of Regulatory Utility Commissioners (NARUC), Onshore U.S. Carbon Pipeline Deployment: Siting, Safety, and Regulation (June 2023); NAPSR, Compendium of State Pipeline Safety Requirements & Initiatives Providing Increased Public Safety Levels compared to Code of Federal Regulations (2022); Mack & Munoz-Patchen, "CO_2 Pipeline infrastructure for Sequestration Projects" 17:1 Texas J. Oil, Gas, and Energy Law 101 (2022); Nordhaus & Pitlick, Carbon Dioxide Pipeline Regulation, 30:1 Energy Law J. 85 (2009).

existing requirements where the physical properties, operating conditions, and end uses of gas- and liquid-phase carbon dioxide pipelines merit unique approaches by phase. By way of example, PHMSA proposes to supplement existing references to "pump(s)" throughout part 195, including the § 195.2 definitions of "line section" and "pipeline or pipeline system," to add language for "compressor(s)," which is more appropriate for use on gas-phase carbon dioxide pipelines.

Carbon Dioxide—Composition

The current definition of "carbon dioxide" at § 195.2, adopted in the 1991 final rule, identifies a precise threshold (more than 90 percent of the molecules in the fluid stream) for a pipeline with carbon dioxide in the stream to be considered a pipeline transporting carbon dioxide under part 195. In the 1989 NPRM, RSPA proposed to define carbon dioxide as "a fluid consisting predominately of carbon dioxide molecules compressed to a supercritical state." In response to that NPRM, Exxon Corporation commented, and RSPA agreed, that because "predominant" means more than half, and because of the difficulty in determining the supercritical point of a mixture of gases, the definition should be changed to be more precise than the proposed definition. In their comment, Exxon Corporation recommended a threshold of 90 percent of the molecules in the fluid stream to aid in the determination of the critical point of the product stream. Similarly, API petitioned RSPA to prescribe a minimum threshold for carbon dioxide content (on the basis of percentage of molecules) for the determination of the critical point of the product stream. RSPA subsequently defined carbon dioxide as a fluid consisting of more than 90 percent carbon dioxide molecules in the 1991 final rule.

PHMSA is now proposing to regulate the transportation of carbon dioxide in any combination of the gas, liquid, or supercritical phases in part 195.[89] As such, operators would no longer need to determine the state or the critical point of the product stream to determine whether the pipeline is regulated under part 195. Regarding the proportion of carbon dioxide molecules within a commodity stream appropriate for regulation under part 195, PHMSA proposes a new threshold of more than 50 percent of the molecules (by molecular count, rather than mass) in the commodity stream. Lowering the threshold of carbon dioxide molecular content from more than 90 percent to more than 50 percent corresponds to the use of "predominant" in RSPA's original proposal for the definition of carbon dioxide in the 1989 NPRM. This approach would ensure that pipelines transporting mixtures of carbon dioxide and other constituents in which carbon dioxide constitutes the majority of molecules in the product stream would be subject to regulatory requirements corresponding to that most common molecular constituent. This approach reflects the common-sense proposition that the properties of a commodity stream are driven in large part by the stream's most predominant constituent. If carbon dioxide constitutes the majority of a fluid stream then that pipeline would be regulated as a carbon dioxide pipeline subject to part 195; alternatively, if the fluid stream is predominantly natural gas, or a flammable, toxic, or corrosive gas, that pipeline would be subject to part 192. PHMSA requests that stakeholders, including operators of carbon dioxide pipelines, provide comments regarding the appropriateness of modifying the percentage of carbon dioxide molecules that constitute a product stream to be "carbon dioxide" under the proposed definition and the feasibility of transporting carbon dioxide at molecular percentages of less than 90 percent. PHMSA also seeks

[89] See section II.C of this NPRM for further information on why PHMSA is proposing all amendments within part 195.

information from stakeholders, if it is available, regarding whether: (1) there are or will be fluid streams transported by pipeline composed of more than 50 percent (by molecular count) carbon dioxide that could pose a hazard to the public or the environment because they are already considered a "gas" under part 192 or a "hazardous liquid" under part 195; (2) there will be pipeline fluid streams newly-subject to PHMSA regulation as carbon dioxide pipelines in which there are other, minority constituents involving greater risks to public safety and the environment than the carbon dioxide in those fluid streams; and (3) there are or will be pipeline fluid streams in which the carbon dioxide composition is below the threshold proposed, but in which the fluid stream is otherwise not one that would be regulated by PHMSA.

PHMSA anticipates concerns from members of industry and the public regarding the consistency of its above proposed approach with the exception at § 195.1(b)(1) stating that part 195 does not apply to "transportation of a hazardous liquid transported in a gaseous state." The definition of "hazardous liquid," as defined at § 195.2, does not include "carbon dioxide." Therefore, the exception at § 195.1(b)(1) does not apply to carbon dioxide, as carbon dioxide is defined and regulated separately from hazardous liquid in part 195, with deliberate attention being made in certain sections throughout the part to differentiate the applicable products, where necessary. This understanding also informs PHMSA's proposal to amend the title of part 195, as discussed in section III.A.1.

Carbon Dioxide as an HVL

In 1979, the Materials Transportation Bureau (MTB), RSPA's and PHMSA's predecessor, issued a final rule enhancing existing requirements at § 195.402 governing written procedures to be prepared and followed by operators of hazardous liquid pipelines for conducting pipeline operations and maintenance and for handling emergencies.[90] The MTB included within its 1979 final rule a definition at § 195.2 for the term "highly volatile liquid or HVL" for use with the revised procedural and reporting requirements. In the 1979 final rule, special procedures were required for pipelines transporting HVLs: those "commodities" whose thermodynamic and chemical characteristics, including a vapor pressure exceeding 276 kPa (40 psia) at 37.8 °C (100 °F), would result in vapor clouds on release to atmosphere. This tendency to form vapor clouds on release, MTB explained, posed a greater hazard to public safety and the environment than releases of other liquid commodities. Two years later, PHMSA revised § 195.2 to replace the reference to "commodity" in the definition of HVL with a reference to "hazardous liquid" to conform with the statutory language of the Hazardous Liquid Pipeline Safety Act of 1979 (Pub. L. 96-129).[91] PHMSA's PSR now contains a number of safety requirements and guidance specific to HVL pipelines, including the following: valve spacing and location (§§ 195.260 and 195.418); pressure testing (§§ 195.302, 195.303 and Appendix B to Part 195); enhanced emergency planning and notification procedures (§ 195.402); pipe movement restrictions (§ 195.424); overpressure safety devices and protection system testing (§ 195.428); and IM implementation (Appendix C to Part 195).

However, because the § 195.2 definition of "HVL" references only hazardous liquids, it does not include carbon dioxide in any phase, despite carbon dioxide meeting the thermodynamic and chemical characteristics described in that definition in the supercritical, liquid, and gas phases (i.e., it will form a vapor cloud when released to the atmosphere and has a

[90] 44 FR 41197 (July 16, 1979).
[91] 46 FR 38357 (July 27, 1981).

vapor pressure in excess of 176 kPa (40 psia) at 37.8°C (100 °F)).[92,93] A release to the atmosphere of carbon dioxide, whether transported in the gas, liquid, or supercritical phases, from a pressurized pipeline will result in the formation of a vapor cloud that can entail severe public safety and environmental consequences because carbon dioxide is denser than air, odorless, and colorless. A carbon dioxide vapor cloud can flow considerable distances from a pipeline unobserved, travel over various terrains, and displace oxygen while settling or filling in low spots. Oxygen displacement can starve gasoline- or diesel-powered equipment, such as first responder and private vehicles, causing such equipment to malfunction or even shut off. Oxygen displacement by carbon dioxide can asphyxiate humans and animals and may lead to death. Further, carbon dioxide can cause disorientation, confusion, and unconsciousness, which can be dangerous for persons caught in a vapor cloud.[94] Lastly, carbon dioxide vapor clouds could contain other carbon dioxide product stream constituents that themselves entail public safety and environmental risks, which, as explained in section II.B above, is an increasingly likely scenario given the increased interest in CCUS infrastructure.

As the carbon dioxide pipeline network is expected to expand over the next several decades as described in section II.B of this NPRM, the public and the environment would experience a greater risk of being exposed to harmful or deadly concentrations of carbon dioxide

[92] Engineering Toolbox (6,450 kPa (935.5 psia) at 25°C (77°F), also *https://www.cheric.org/research/kdb/hcprop/showprop.php?cmpid=1943*.
[93] DNV-RP-F104. Edition February 2021, amended September 2021, § 2.2: "Supercritical CO_2 is a highly volatile fluid that will rapidly evaporate when depressurized to ambient conditions."
[94] Accufacts' Perspectives on the State of Federal Carbon Dioxide Transmission Pipeline Safety Regulations as it Relates to Carbon Capture, Utilization, and Sequestration within the U.S., Richard B Kuprewicz, March 23, 2022

in the event of a release from a carbon dioxide pipeline facility.[95] The public would benefit from those pipelines being subject to the heightened safety measures already required of pipelines transporting other HVLs, which carry similar risks and cause similar safety and environmental consequences due to their tendency to form vapor clouds that can migrate beyond the immediate location of a pipeline. PHMSA is therefore proposing to revise the definition of a "highly volatile liquid or HVL" to explicitly include carbon dioxide. The public would benefit from the more stringent HVL requirements because carbon dioxide in each phase behaves similarly to other HVLs when released from a pipeline. Operators of HVL pipelines must comply with additional requirements, including, but not limited to, the following: valve spacing and location (§§ 195.260 and 195.418); pressure testing (§§ 195.302, 195.303 and Appendix B to Part 195); enhanced emergency planning and notification procedures (§ 195.402); pipe movement restrictions (§ 195.424); overpressure safety devices and protection system testing (§ 195.428); and IM program implementation (Appendix C to Part 195). PHMSA also proposes certain other enhanced requirements for HVL pipelines relating to: safety related condition reporting (§ 195.55, discussed in section III.B.1); vapor detection and alarm systems (§§ 195.263, 195.429, and 195.452(i)(5)); and IM, including vapor dispersion analysis (§§ 195.452 and 195.456), among others.

Close Interval Survey

As discussed in detail in section III.E. of this NPRM, PHMSA is proposing to require operators perform close interval surveys (CIS) when converting a pipeline to service for the

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[95] DNV-RP-F104. Edition February 2021, amended September 2021, § 1.1

transportation of carbon dioxide in accordance with part 195 from a pipeline previously not subject to part 195. This conforming change includes a new definition for "close interval survey" under § 195.2. The proposed definition reflects the definition added to part 192 at § 192.3 and is supported by the analysis within the rulemaking adding that definition.[96]

Appropriateness of Proposed Revisions to Regulatory Definitions

PHMSA expects the proposed amendments at § 195.2's regulatory definitions, particularly its proposed revisions to "carbon dioxide" and "HVL," as described above, would be reasonable, technically feasible, cost-effective, and practicable for affected pipeline operators. As discussed above, those proposed amended definitions improve alignment of PHMSA's regulatory oversight of carbon dioxide pipelines with anticipated new product stream compositions and the hazardous characteristics of pipeline-transported carbon dioxide. Rather than creating an entirely new suite of bespoke regulatory requirements, PHMSA expects the choice to leverage longstanding, proven part 195 requirements for supercritical-phase carbon dioxide and HVL pipelines will minimize administrative burdens for pipeline safety regulatory authorities (both PHMSA and the state regulators) and compliance burdens for operators (many of whom may already have part 195-compliant supercritical-phase carbon dioxide or HVL pipelines).[97] PHMSA also understands its proposed approach could be particularly valuable to

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[96] Docket No. PHMSA-2011-0023; Amdt. No. 192-132. See, e.g., PHMSA, "Final Rule: Pipeline Safety: Safety of Gas Transmission Pipelines - Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments,
87 FR 52224, 52238-40 (Aug. 24, 2022)).
[97] Not all of the existing requirements of part 195 pertinent to currently regulated supercritical-phase carbon dioxide pipelines would apply to newly regulated gas-phase, liquid-phase, or lower-concentration carbon dioxide pipelines; similarly, not every existing part 195 requirement for HVL pipelines would automatically attach to every carbon dioxide pipeline. Rather, pursuant to 49 U.S.C. 60104(b), initial design (subpart C), installation, inspection,

interstate carbon dioxide pipelines that would otherwise be subject to potentially conflicting requirements of different states. Further, the NPRM's proposed extension of existing part 195 requirements for supercritical-phase carbon dioxide pipelines is consistent with the approach taken in pertinent industry standards and technical documents, which generally draw no sharp distinction between different physical states and compositions of carbon dioxide product streams.[98] Similarly, the pipeline safety regulatory regimes of other countries extend many of the requirements of HVL pipelines to carbon dioxide pipelines.[99]

Additionally, the existing part 195 requirements this rulemaking would extend to new physical states and compositions of carbon dioxide pipelines (as well as HVL-specific requirements being extended to all carbon dioxide pipelines) are not outlandish; rather they are longstanding requirements, each of which were adopted only after an extensive, APA-compliant rulemaking process and advisory committee consultation. Many of the requirements extended in this rulemaking reflect or incorporate by reference consensus industry standards and recommended practices, or otherwise are the sort of common-sense, typical measures that that any reasonably prudent carbon dioxide pipeline operator would undertake in ordinary course,

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construction (subpart D), and testing (subpart E) requirements would only apply on a going-forward basis to newly constructed, converted, replaced, or changed carbon dioxide pipelines. Other part 195 requirements (e.g., subpart B reporting requirements and subpart F operations and maintenance requirements) would apply to all newly regulated, existing carbon dioxide pipelines, beginning on the effective date of any final rule.

[98] See, e.g., Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document; Guidelines for Preparedness and Initial Response to a Pipeline Release of Carbon Dioxide (CO_2)", API, Liquid Energy Pipeline Association, and National Association of State Fire Marshals; (August 2023) pp. 1; Det Norske Veritas (DNV), DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines at pp.6 (Sept. 2021); PRCI, Pipeline Transportation of CO_2 SOTA, Gap Analysis and Future Project Roadmap at pp. iii (Nov. 2023).

[99] See, e.g., PRCI, Pipeline Transportation of CO_2 SOTA, Gap Analysis and Future Project Roadmap at pp. 157 (Nov. 2023) (noting that Canadian pipeline safety regulations regulate carbon dioxide pipelines as "high vapor pressure lines.")

given the potential lost commercial value and hazards to public safety and the environment from releases from their pipelines. Also, should an operator identify a compelling need for regulatory flexibility, the PSR provides for special permit procedures at § 190.341 to request a deviation from specific regulatory requirements.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 believes that operator compliance timelines—based on an effective date of the proposed requirements one year after the publication date of a final rule in this proceeding, which timeline would necessarily be in addition to the time since issuance of this NPRM—would provide operators ample time to implement requisite changes and manage any related compliance costs and implementation challenges.

B. Expanded Reporting Requirements—§§ 195.48, 195.49, 195.54, 195.55, and 195.61

1. Expanded Safety-Related Condition Reporting—§ 195.55

Section 195.55 prescribes which safety related conditions (SRCs) an operator is required to report to PHMSA, as well as when operators are exempted from making those reports. There are six conditions meeting the criteria of an SRC at § 195.55: (1) general corrosion resulting in a pipe wall thickness less than that required for the MOP, or localized corrosion pitting to a degree where leakage might result; (2) unintended movement or abnormal loading of a pipeline by environmental causes that impairs its serviceability; (3) any material defect or physical damage that impairs pipeline serviceability; (4) any malfunction or operating error that causes the pressure of a pipeline to rise above 110 percent of its MOP; (5) a pipeline leak that constitutes an emergency; and (6) any SRC that could lead to an imminent hazard and causes a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.

Pursuant to § 195.55(b)(1), SRC reports are not required for conditions on pipelines that are more than 220 yards from any building intended for human occupancy or outdoor place of assembly, regardless of the product transported. Superseding this exemption, regardless of the distance of the SRC on the pipeline from any building intended for human occupancy or outdoor place of assembly, SRC reports are required when the condition occurs within the right-of-way of an active railroad, paved road, street, or highway, or when they occur offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water.

When an SRC report is required, operators submit the following information to PHMSA: name of the operator; date of report; contact information for the submitter of the report and the individual who made the SRC determination; date of discovery of condition and date of condition initiation; location of condition; description of condition and the circumstances of its discovery and safety risks; and corrective action(s) taken and planned by the operator. PHMSA reviews these notifications when received and then follows up with the submitting operators to determine additional details on each, prompting government intervention, if needed, to prevent known hazardous conditions from going uncorrected and in some cases avoiding the occurrence of an incident or accident. SRC reports are available to the public at *https://www.phmsa.dot.gov/data-and-statistics/pipeline/leading-indicators-srcr-and-im-notifications*.

Section 195.55 does not contain differing requirements for SRC reporting exceptions based on commodity type, although pipeline transportation of hazardous liquid, carbon dioxide, and HVL pipeline systems can each present different risks to public safety and the environment depending on the product transported. Pipeline transportation of different product streams may entail different risks to pipeline integrity as a function of composition of the product stream (e.g., the corrosivity of their constituents). Once pipeline integrity has been compromised, public safety and environmental consequences can be significant. As discussed in section II.A of this NPRM, pipelines transporting carbon dioxide present serious asphyxiation risks to individuals and animals within released vapor clouds, as well as environmental harms associated with the release of GHGs. The 2020 Satartia accident showed that releases from pipelines transporting carbon dioxide can reach and cause elevated concentrations of carbon dioxide within residences and other buildings intended for human occupancy at distances much greater than the 220 yards in the exception at § 195.55(b)(1); additionally, as more carbon dioxide pipeline transportation is put in place to support CCUS infrastructure (as discussed in section II.B above), some of those carbon dioxide pipelines may include other constituents, posing additional public safety and environmental risks. Similarly, releases of certain HVLs, including anhydrous ammonia and various product streams containing hydrogen sulfide, can also present serious asphyxiation and toxicity risks. While some portion of the released HVL may dissipate into the environment in the immediate vicinity of the release site, some released HVLs can also form dense vapor clouds, similar to carbon dioxide, that can negatively impact operator personnel, the public, and the environment far from the pipeline. In addition, when release rates exceed the dissipation rate for HVL vapors (including those HVLs with a density less than air), which can occur during a rupture event, vapor clouds can still form in excess of NIOSH IDLH concentrations for asphyxiation and toxicity.[100] An example of this occurred when a pipeline ruptured near Tekamah, Nebraska in 2016.[101] In this accident, an 8-inch pipeline transporting anhydrous ammonia ruptured due to corrosion fatigue cracking, causing the formation of an ammonia vapor cloud, which took the life of a nearby resident and injured two others. Vapor clouds from releases on pipelines transporting HVLs can migrate significant distances, in some cases miles, based on local topography and weather conditions, and can present an unreasonable risk to the public.

Since SRCs represent a safety risk to the pipeline, they can be considered as leading safety indicators and may alert the operator and PHMSA to systemic issues on specific pipelines or a class of similarly situated pipelines prior to the onset of a reportable accident. As such, PHMSA maintains communication with operators on reported SRCs to ensure planned remedial actions are sufficient and completed in a timely manner. Expanding the scope of received SRC reports from HVL pipelines, including carbon dioxide, could allow PHMSA to identify systemic issues on these pipeline systems before accidents occur. The removal of the distance-based exception at § 195.55(b)(1) for HVL pipelines only (including carbon dioxide pipelines) is consistent with the proposition (discussed above) that the public safety and environmental risks posed by releases from those pipelines can exceed the existing, one-size-fits-all, 220-yard boundary. PHMSA expects the information received from this expanded SRC reporting requirement will prove especially important for trend analysis to identify issues in connection

[100] *https://www.cdc.gov/niosh/idlh/intridl4.html*

[101] NTSB, *Pipeline Accident Brief: Magellan Pipeline Anhydrous Ammonia Release*, PAB-20/01, January 29, 2020, (*https://www.ntsb.gov/investigations/AccidentReports/Reports/PAB2001.pdf*).

with the anticipated buildout of carbon dioxide pipeline infrastructure in the near future (some of which may transport carbon dioxide in novel phases or product stream compositions), as discussed in section II.B.

For these reasons, PHMSA is proposing to require operators to submit SRC reports for the listed conditions on all pipelines transporting HVLs, including carbon dioxide, regardless of the distance from any building intended for human occupancy or outdoor place of assembly. This proposal provides additional protection to the public through the notification to PHMSA of crucial safety information, including details on the condition and its discovery, any significant effects of the condition on safety, the commodity transported, and any completed or planned corrective action(s), including the anticipated schedule for starting and concluding those action(s). This would also allow PHMSA to ensure operators take remedial actions on pipelines transporting HVLs, including carbon dioxide, and could prevent SRCs from escalating to reportable accidents with proper oversight.

2. Annual and Accident Report Form Changes

Each operator of a pipeline regulated under part 195 must annually complete and submit DOT Form PHMSA F 7000–1.1 (annual report) for each type of pipeline facility operated at the end of the previous year. An operator must submit the annual report by June 15 each year. The annual report is required by § 195.49 and must be filed according to § 195.58. The annual report provides PHMSA with information on pipeline infrastructure, operating conditions, and preventative and mitigative actions undertaken by operators. This information includes: integrity inspections completed and remediation activities performed as a result of those inspections; miles of pipeline by decade of installation; total pipeline segment miles that could affect HCAs;

miles of pipeline cathodically protected; and other key safety information. PHMSA uses this information to track aggregate pipeline safety trends and run year-over-year comparisons by operator. Annual report data is available to the public at *https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids*.

The same operators are also required to submit an accident report form to PHMSA when an accident meets the criteria of § 195.50. The form for operators of hazardous liquid or carbon dioxide pipelines is DOT Form PHMSA F 7000-1, and the form for hazardous liquid gravity or reporting-regulated gathering pipelines is DOT Form PHMSA F 7000-2. Accident reports must be submitted to PHMSA as soon as practicable but not more than 30 days after discovery of the accident. Requirements for submitting accident reports are found at § 195.54 and § 195.58. The accident report includes information on the affected pipeline segment, injuries and fatalities that occurred, volume of product released, accident cause, and repair activities. PHMSA uses the data from accident reports to identify emerging safety issues, both global and operator-specific; flag complex accidents for further investigation by PHMSA; and provide extra oversight on repair and remediation activities following accidents. Accident reports are available to the public at *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data*.

With the proposed addition of gas- and liquid-phase carbon dioxide pipelines to part 195 applicability, PHMSA has identified the need for additional information in both the annual and accident reports. In all three forms (DOT Form PHMSA F 7000–1.1, DOT Form PHMSA F 7000-1, and DOT Form PHMSA F 7000-2), PHMSA proposes that carbon dioxide operators identify the phase(s) of the pipeline for which the report is being submitted. Four options for phase would be provided: (1) gas phase, (2) liquid phase, (3) supercritical phase, and (4) mixed phase. This information would aid identification of the growing infrastructure of carbon dioxide pipelines, including safety trends that is anticipated due to motivating factors such as 45Q credits (as discussed in Section II.B of this NPRM). This change would be proposed as a drop-down option under the commodity type of carbon dioxide. PHMSA also proposes corresponding edits to the instructions for each form.

Second, PHMSA proposes additional questions on the annual report form (DOT Form PHMSA F 7000–1.1) relating to leaks that for carbon dioxide pipeline operators. PHMSA proposes operators provide information on the number of leaks operators identify on their carbon dioxide pipeline systems. PHMSA also proposes operators provide information on the total, summed volume of carbon dioxide pipeline releases to the environment from their systems, including releases from accidents, leaks (including those from pipelines, pump and compressor stations, meters and regulators, and other equipment), planned or unplanned blowdowns, and other equipment that may vent to the environment. As discussed in II.B and III.C.2, leaks and other releases on carbon dioxide pipelines present a risk to both the public and the environment and contribute to climate change. The addition of this information to the annual report would allow PHMSA to identify emerging safety trends that cause leaks and could alert PHMSA to the presence of systemic issues on specific pipeline networks (or classes of similarly situated pipelines) transporting carbon dioxide. PHMSA also proposes corresponding edits to the instructions for the annual report.

3. Clarifications and Corrections—§§ 195.48, 195.49, 195.54, and 195.61

In this rulemaking, PHMSA proposes corrections to report form titles at §§ 195.48 and 195.54. At § 195.48, PHMSA proposes a correction to the title of the annual report to the correct name of "DOT Form PHMSA F 7000-1.1" for operator clarity. This change is also consistent with the accurate title for the annual report currently found at §195.49. Section 195.54 requires operators to submit accident reports within 30 days of the date of the accident when reporting is required by § 195.50. PHMSA has two separate accident report forms, DOT Form PHMSA F 7000-1 and DOT Form PHMSA F 7000-2, for operators to use depending on the type of pipeline on which the accident occurred. The language at § 195.54, however, only references DOT Form PHMSA F 7000-1, which can cause confusion for operators of gravity and reporting-regulated-only gathering hazardous liquid pipelines, who, when required, report accidents under DOT Form PHMSA F 7000-2. PHMSA proposes correcting the reference to a single report title to ensure § 195.54 reflects the two different accident reports and for which group of pipelines each form is applicable, for operator clarity.

At § 195.49, PHMSA is also proposing to remove an outdated reference to the deadline for the 2010 annual report, which is no longer relevant, as all 2010 annual reports required submission in 2011. This change provides clarity by simplifying and shortening this section, aiding the reader. Additionally, this rulemaking proposes conforming changes to the list of commodities requiring separate annual reports by § 195.49, which currently includes HVLs and carbon dioxide. As this rulemaking proposes changes to the definition of HVL at § 195.2 to include carbon dioxide, and a separate annual report is required for carbon dioxide and HVLs, this NPRM proposes to clarify that operators of carbon dioxide pipelines are not required to submit duplicate annual reports under both HVLs and carbon dioxide. Instead, this NPRM proposes to require operators of carbon dioxide pipelines to submit annual reports solely under the commodity type of carbon dioxide by clarifying the reporting requirement for HVLs is for non-carbon dioxide HVLs only. This conforming change prevents duplicative reporting by operators and is also consistent with how operators of both carbon dioxide pipelines and HVL pipelines (under the current definitions) submit annual reports today, thus reducing confusion by continuing current practices and allowing PHMSA to continue to obtain necessary safety data.

Section 195.61 codifies in the PSR a self-executing, statutory requirement for operators of hazardous liquid pipeline facilities to provide geospatial data for the National Pipeline Mapping System (NPMS) as mandated by Congress in section 15 of the Pipeline Safety Improvement Act of 2002 (codified at 49 U.S.C. 60132).[102] That statutory language requires operators of pipeline facilities to provide to the Secretary of Transportation certain specified information, including geospatial data appropriate for use in NPMS or data that can readily be converted to NPMS data. NPMS is a geospatial dataset that contains information about PHMSA-regulated pipeline facilities. Section 15 also requires operators to provide periodic updates of that information to reflect changes and other information as required by the Secretary.[103] To implement that statutory mandate, PHMSA in 2015 promulgated § 195.61 to require each operator of a hazardous liquid pipeline facility to provide to PHMSA for inclusion within NPMS specific safety-critical information for their pipeline facilities, including the locations of pipelines and related infrastructure, the names and contact information of pipeline operators, and other attributes of their pipelines (such as commodities transported and diameter).[104]

Section 195.61 does not explicitly reference currently regulated supercritical-phase carbon dioxide pipelines. However, operators of those pipelines have, consistent with the self-

[102] Section 15 of Pub. Law. 107-355 (December 17, 2002)
[103] Bill Summary, CRS (November 11, 2002), *https://www.congress.gov/bill/107th-congress/house-bill/3609/text.*
[104] 80 FR 12762 "Pipeline Safety: Miscellaneous Changes to Pipeline Safety Regulations"

executing statutory language, submitted geospatial data to PHMSA that corresponds to and matches with the mileage reported on DOT Form PHMSA F 7000-1.1 (annual report), in accordance with § 195.49, as of reporting year 2022.

This NPRM proposes to amend § 195.61 to make explicit that NPMS reporting requirements would apply to carbon dioxide pipelines, regardless of the phase of carbon dioxide transported. Although existing practice is for currently regulated carbon dioxide pipelines to submit NPMS data, supporting that practice with explicit regulatory language at § 195.61 would ensure that pipeline safety stakeholders—including operators, emergency responders, excavators, elected officials, public interest advocates, and PHMSA and State regulators—continue to have access to important safety-related information. Access to carbon dioxide pipeline geospatial and operational characteristics data in NPMS reinforces operator damage prevention programs required by § 195.440. The safety-critical information within NPMS also reinforces planning requirements (§ 195.402), coordination/communication requirements (§§ 195.402 and 195.408), and response efforts by operators and local authorities. The requirement to submit data to NPMS also dovetails with PHMSA requirements ensuring safe operation and maintenance activities on carbon dioxide pipelines, including those on maintenance of accurate system maps and records (§ 195.404) and leak detection programs (§§ 195.134 and 195.444). Inclusion of carbon dioxide pipelines within NPMS will also improve the ability of third parties (such as other operators, public interest advocates, or members of the public) to report leaks, ruptures, and other unsafe conditions to the operator or emergency response officials. Lastly, PHMSA expects the anticipated benefits outlined above from improved alignment of § 195.61 regulatory text with historical industry practice and statutory language would also prove valuable as the U.S. carbon dioxide pipeline infrastructure, some of which may be operated by entities unfamiliar with the self-executing NPMS mandate within the Pipeline Safety Laws, changes to incorporate more mileage, applications, and different phases (liquid and gas) of carbon dioxide.[105]

4. Appropriateness of Proposed Amendments to Reporting Requirements

PHMSA expects the proposed amendments to reporting requirements would be reasonable, technically feasible, cost-effective, and practicable for affected carbon dioxide pipeline operators. PHMSA expects the proposed amendments to annual and accident reporting requirements will generally involve minimal burden for operators, in that they are merely conforming revisions to existing PHMSA reporting requirements, introduced to reflect the expansion of part 195 to novel compositions and physical states of carbon dioxide product streams. Further, the enhanced information regarding leaks proposed in annual reports for carbon dioxide pipelines better aligns subpart B reporting requirements with information that operators may already compile when complying with either leak detection system requirements at §§ 195.134 and 195.444; leak detection-pertinent IM program requirements at § 195.452 and Appendix C to Part 195; or even EPA emissions reporting requirements under 40 CFR part 60. Similarly, PHMSA's proposed enhancement of annual reporting of information on intentional releases (e.g., venting or blowdown) of carbon dioxide could leverage information that some operators may already compile when complying with IM program requirements at § 195.452 and Appendix C to Part 195 directing operators to mitigate impacts of any release on HCAs; or EPA

[105] PHMSA submits that the public safety and environmental benefits anticipated from its proposed revision of § 195.61 would also implicate its more general statutory authorities to promulgate safety (discussed at length in sections II.C and V.A) and reporting requirements (discussed in section V.A) for pipeline facilities transporting carbon dioxide.

emissions reporting requirements under 40 CFR part 60. Meanwhile, PHMSA's proposed amendment of NPMS reporting requirements to mention carbon dioxide pipelines explicitly aligns regulatory text with existing practice by carbon dioxide pipeline operators; further, the information affected operators would need to submit in NPMS includes data (including the precise location of their pipelines, the commodity transported, etc.) that any reasonably prudent operator would maintain in ordinary course to safeguard a commercially valuable commodity and protect public safety and the environment from releases of that commodity. Lastly, although PHMSA acknowledges that its proposed removal for HVL pipelines of the 220-yard distance exception from SRC reporting requirements at § 195.55(b)(1) could entail incremental compliance burdens, PHMSA understands those burdens would likely be minimal in practice. The occasions for submission of an SRC identified at § 195.55 generally pertain to safety-critical issues that can trigger a variety of other requirements (e.g., documentation, investigation, or remediation) in the PSR, to which the SRC reporting obligation would be a minimal incremental additional burden. Additionally, even as PHMSA is proposing to remove that distance-based exception, other exceptions at § 195.55(b)—e.g., for reportable accidents at § 195.50—would remain to mitigate any incremental burden of PHMSA's proposal. Also, should an operator identify a compelling need for regulatory flexibility, the PSR provides for special permit procedures at § 190.341 to request a deviation from specific reporting requirements.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 believes that operator compliance timelines—based on an effective date of the proposed requirements one year after the publication date of a final rule in this proceeding (which timeline would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite changes and manage any related compliance costs and implementation challenges.

C. Comprehensive Design, Construction, Installation, and Testing—§§ 195.3, 195.8, 195.18, 195.111, 195.116, 195.120, 195.134, 195.210, 195.248, 195.260, 195.262, 195.263, 195.302, 195.306, 195.309, 195.444, and 195.588

Overview

Subparts C, D, and E of part 195 contain the design, construction, and pressure testing requirements for hazardous liquid and carbon dioxide pipelines, respectively. When considering how a pipeline is designed and constructed, and any pressure testing performed as part of start-up activities or subsequently, it is important to consider the product transported, including all constituents of the product stream.

As noted in section II.A of this NPRM, the properties of carbon dioxide are unique when compared to most hazardous liquids transported under part 195. Due to these characteristics and those of the possible constituents in the product stream, PHMSA proposes (1) enhanced pipeline design requirements to mitigate fracture propagation at § 195.111, and (2) enhanced valve design requirements to ensure material compatibility at § 195.116. Both proposals are covered in more detail below in section III.C.1.

PHMSA's regulations have long recognized the safety risks associated with leaks of hazardous liquids and the need for effective leak detection systems on those pipelines. In a 2000 final rule,[106] RSPA adopted § 195.452(i)(3) requiring hazardous liquid and (supercritical) carbon dioxide pipeline operators that could affect HCAs to use leak detection systems. In a 2019 final rule,[107] PHMSA expanded the use of leak detection systems to all pipelines transporting hazardous liquids in a single phase, with the exception of offshore gathering and regulated rural gathering pipelines, to "help mitigate the effects of hazardous liquid pipeline failures that occur outside of HCAs." Although leaks on carbon dioxide pipelines—no matter what phase—can also cause significant public safety risks, part 195-regulated carbon dioxide pipeline systems that would not affect HCAs are not required by the PSR to install, operate, and maintain leak detection systems compliant with § 195.134 or § 195.444. Leaks of any type can degrade into catastrophic failures—sometimes referred to as the "leak-before-break" concept—and may be a particularly significant concern for carbon dioxide pipelines because of the increased potential for brittle fracture due to the Joule-Thomson effect – also referred to as throttling or the cooling of a fluid due to rapid reduction in pressure – at the leak location.[108,109] Therefore, PHMSA proposes modifications to the leak detection system requirements at §§ 195.134 and 195.444 to include all carbon dioxide pipelines, no matter what phase, whether those pipelines would be subject to IM requirements or not. These proposals are covered in more detail in section III.C.2 below. PHMSA is otherwise retaining and not proposing any further modifications to the

[106] 65 FR 75377, "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline)," (December 1, 2000).
[107] 84 FR 52260, "Pipeline Safety: Safety of Hazardous Liquid Pipelines," (October 1, 2019).
[108] Wilkowski, "Leak-Before-Break, What Does It Really Mean?" 122 Journal of Pressure Vessel Technology pp. 267 (Aug. 2000).
[109] See, e.g., DiBiagio, et al, EU 28918, Final Report: Requirements for Safe and Reliable CO_2 Transportation Pipeline (SARCO2) pp. 99 (2017).;

requirements at §§ 195.134 and 195.444 that each new CPM leak detection system comply with the applicable requirements of the API RP 1130 standard.

PHMSA has a longstanding requirement at § 195.210 that directs operators of new carbon dioxide and hazardous liquid pipelines to select pipeline right-of-way to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. In keeping with this requirement, and considering the unique risks presented by carbon dioxide pipelines, this NPRM proposes to add a new requirement for operators of newly constructed, replaced, relocated, otherwise changed, or converted to part 195 service onshore carbon dioxide pipelines that select a right-of-way (or exist in an existing right-of-way) located within two miles of any residence, business, or place of public assembly to document the reasons such a location was impracticable to avoid. This NPRM also proposes to require those operators to perform a population density survey along the pipeline route to establish an emergency planning zone. Further details on the proposed population density survey, required communications within the emergency planning zone, and other associated requirements are located within section III.C.3 of this NPRM.

Depth of cover is a key mechanism for the prevention of excavation-related damages to buried pipelines. Industry standard practices at ASME B31.4-2006, a document that is already incorporated by reference at § 195.3 for use at §§ 195.110(a) and 195.452(h), specify a minimum depth of cover of 48 inches for normal excavation in agricultural areas. Consistent with this standard, PHMSA proposes to add a new row at § 195.248 to the table of locations and corresponding depth of cover of 48 inches for normal excavation in agricultural areas.

The physical and chemical characteristics of HVLs can contain numerous mechanisms for human harm, including asphyxiation, toxicity, flammability, and combustibility (see sections

II.A and III.C.5). These releases are most likely to occur at facilities where personnel may be present intermittently, including pump or compressor stations, meter stations, valve stations, and other facilities, such as launcher and receiver sites. To protect operator personnel at these facilities and support the timely identification of these releases, PHMSA is proposing to require operators of newly constructed, replaced, relocated, otherwise changed, or converted to service HVL pipelines (including carbon dioxide pipelines) to have fixed vapor detection and alarm systems at certain facilities. These systems are a tool commonly used today in industrial applications to identify hazardous concentrations of carbon dioxide and other HVLs in working environments. Further details on the proposed requirements of these systems can be found in section III.C.5 of this NPRM; proposed maintenance requirements for these systems are detailed in section III.D.2.

As discussed in sections II.A and II.D of this NPRM, releases from carbon dioxide pipelines have the potential to travel significant distances from the release origin and can result in the formation of hazardous, asphyxiating vapor clouds. During pressure testing performed under subpart E of part 195, failures can occur, and the pressure test medium can be released. Accordingly, PHMSA is proposing to remove carbon dioxide as an acceptable test medium at § 195.306.

Additionally, PHMSA proposes modifications at § 195.588 to refer to the proposed new § 195.309, which will consolidate and revise part 195 requirements for spike hydrostatic pressure testing requirements. As PHMSA is proposing to require spike hydrostatic pressure testing on a subset of pipelines (see § 195.5 proposals under III.E), and the preexisting requirements on spike hydrostatic pressure tests within § 195.588 conflict with some portions of subpart E of part 195, PHMSA proposes the creation of a new section that clearly outlines the requirements for spike hydrostatic pressure tests. PHMSA also proposes references to this new section where necessary, including at § 195.588.

Lastly, PHMSA proposes conforming changes throughout subparts C, D, and E, as well as at §§ 195.3 and 195.8, to reflect other proposed changes. These conforming changes fall into three main categories: (1) additional incorporation by reference of an industry standard; (2) additional effective dates for proposed requirements for newly regulated carbon dioxide pipelines; and (3) harmonizing other sections and requirements with the proposed modifications to the definitions of carbon dioxide and HVL. These changes are discussed in more detail in III.C. 8 below.

1. Enhanced Design Requirements—§§ 195.111 and 195.116

Section 195.111 requires that pipelines transporting carbon dioxide be designed to mitigate fracture propagation. Fracture propagation is a phenomenon in which a fracture of the pipeline steel continues to spread unchecked. Fracture propagation can be prevented through adequate pipeline steel toughness[110] or be halted by crack arrestors.[111] The PSR does not contain any specifications or guidance on how operators must mitigate fracture propagation pursuant to § 195.111, such as those measures explicitly referenced in part 192 regulations for gas pipelines

[110] When referring to pipeline steel, toughness is the ability of a metal to deform plastically and absorb energy prior to fracture. Plastic deformation of the pipeline steel occurs when the steel permanently changes shape in response to stress but does not fracture. Plastic deformation is preferred over ductile and brittle fracture, as no leak of product occurs.
[111] A "crack arrestor" is a structural engineering device that serves to contain cracks, helping to prevent the catastrophic failure of a pipeline. A crack arrestor can be as simple as a thicker ring of pipe or may be constructed of a special material designed to withstand deformation.

(e.g., minimum pipeline toughness requirements, specific testing to ensure toughness values, or details on the use of crack arrestors).

Due to the highly volatile nature of carbon dioxide and high operating pressures on all carbon dioxide pipelines (well above atmospheric pressure), carbon dioxide rapidly decompresses upon release. As noted in the 1989 NPRM,[112] this decompression causes a rapid localized temperature drop, thereby increasing the risk of brittle fracture of the pipeline. For that reason, the final rule in that proceeding adopted special design considerations within part 195 to prevent brittle fractures of the pipeline steel. Fracture initiation (e.g., brittle fracture) and subsequent propagation (e.g., running ductile fractures) has remained a focus of concern for the integrity of carbon dioxide pipelines.[113] As noted in Section II.D above, the Satartia accident demonstrated potential indications of both brittle and ductile fracture.

This NPRM proposes to enhance § 195.111 by providing explicit requirements on how operators of carbon dioxide pipelines must mitigate fracture propagation through design on newly constructed, replaced, relocated, otherwise changed, or converted carbon dioxide pipelines; these requirements are highly similar to the fracture control measures found at § 192.112(b), which provide additional design criteria for natural gas pipelines operating under an alternative maximum allowable operating pressure (MAOP) in accordance with § 192.620.[114]

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[112] RSPA, 54 FR 41912, "Transportation of Carbon Dioxide by Pipeline," (October 12, 1989), pp. 2.
[113] See, e.g., PRCI, Pipeline Transportation of CO2 SOTA, Gap Analysis and Future Project Roadmap 1, 21-22 (Nov. 2023).
[114] The differences between the proposed language at § 195.111 and the existing requirements at § 192.112(b) for fracture control measures would improve consistency with relevant language in the consensus industry standard API Specification 5L incorporated by reference in both sections. That said, PHMSA has retained language at § 192.112(b)(2)(iv)(B) to ensure that the average shear area observed does not mask exceptionally low individual drop weight tear test results, with a measure of additional conservatism given the concerns regarding fracture as a failure mechanism for carbon dioxide pipelines discussed in this section III.C.1.

The alternative MAOP fracture control requirements, which were first included in part 192 regulations in 2008,[115] have shown through years of experience to sufficiently reduce the risk of ductile and brittle fracture on high-pressure gas transmission pipelines. No failures related to pipeline toughness have occurred to date on part 192-regulated pipelines opting for the alternative MAOP requirements at § 192.112.

PHMSA proposes to modify § 195.111 for newly constructed, replaced, relocated, otherwise changed, or converted carbon dioxide pipelines in five key areas related to pipeline toughness and fracture control. First, PHMSA proposes to require carbon dioxide pipeline operators to consider the full range of relevant parameters to which the pipe will be exposed to over its operating lifetime when evaluating resistance to fracture initiation. If unexpected situations or changes in operating conditions result in a change in these parameters during operation, such that they are outside the bounds of those an operator had previously analyzed, PHMSA proposes that operators will be required to review and update their evaluations, and implement remedial measures, to ensure continued resistance to fracture initiation. This requirement is proposed at subparagraph § 195.111(a)(1). Proposed subparagraph § 195.111(a)(2) would require operators to adjust the pipe toughness based on the pipe grade and operating parameters discussed at § 195.111(a)(1) to ensure the pipe toughness is adequate for those factors.

Second, operators would be required to ensure fracture arrest within certain lengths of pipe to prevent long running fractures. Proposed subparagraph § 195.111(a)(3) would require

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[115] PHMSA, 73 FR 62147, "Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines," (October 17, 2008).

operators of newly constructed, replaced, relocated, otherwise changed, or converted carbon dioxide pipelines to ensure at least a 99 percent probability of fracture arrest within 8 pipe lengths[116] (not to exceed 320 feet) and at least a 90 percent probability of fracture arrest within 5 pipe lengths (not to exceed 200 feet). Operators can meet this requirement through sufficient pipe toughness and the use of crack arrestors. This proposal would prevent uncontrolled, extensive running fractures, which are fractures that continue from pipe joint to pipe joint uninterrupted.

Third, PHMSA proposes that carbon dioxide pipelines would have to pass several tests to demonstrate the pipeline metal would deform plastically before fracturing and reduce the risk that fractures would initiate. Proposed § 195.111(a)(4) and subparagraphs (i) and (ii) would require operators of newly constructed, replaced, relocated, otherwise changed, or converted carbon dioxide pipelines to perform toughness testing consistent with industry best practices contained within Annex G of API Specification 5L,[117] including testing methods, acceptance criteria for testing, and required inspection documents.

Fourth, PHMSA proposes at paragraph § 195.111(b) and its corresponding subparagraphs that the toughness properties for newly constructed, replaced, relocated, otherwise changed, or converted carbon dioxide pipelines meet the requirements of Annex G of API Specification 5L, "PSL 2 pipe with resistance to ductile fracture propagation,"[118] including the minimum Charpy

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[116] A length of pipe, also known as a pipe joint, is the section of pipe between two adjacent girth (circumferential) welds.
[117] API Specification 5L prescribes the requirements for the manufacture of new seamless and welded steel line pipe. Annex G is a supplementary extension to that standard.
[118] PSL 2 refers to product specification level 2, an API designation for a specification of pipe.

v-notch absorbed energy requirements. This NPRM also proposes that these toughness properties address the potential for the initiation, propagation, and arrest of fractures, and consider any correction factors needed to address the pipe grade, operating conditions, or product compositions that may not be specified in that standard.

Lastly, to the extent it would be physically impossible for pipe to meet toughness standards under certain conditions, PHMSA proposes that crack arrestors would be required to halt fractures within the lengths of pipe (i.e., joints of pipe separated by girth welds) specified at proposed § 195.111(a)(3). As proposed at § 195.111(a)(3), operators would be required to design their pipeline so that, in the case of a failure involving a fracture, the fracture is arrested within five pipe lengths (typically around 200 feet or 61 meters) 90 percent of the time and is arrested within eight pipe lengths (typically around 320 feet or 98 meters) 99 percent of the time. Proposed § 195.111(c) would allow operators to use alternative means of crack arrest, which could include mechanical means of arrest or design features, such as the use of composite sleeves, spacing, increases in wall thickness at appropriate distances, or other methods to comply with the requirement at § 195.111(a)(3).

As these proposals would only be applicable to carbon dioxide pipelines constructed, replaced, relocated, otherwise changed, or converted to service after the effective date of the final rule, PHMSA is proposing to retain the original language of § 195.111 in a new paragraph (d). Carbon dioxide pipelines constructed prior to a final rule's effective date that transport carbon dioxide meeting the current definition (a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state) would still be required to be designed to mitigate the effects of fracture propagation in accordance with the original requirement at § 195.111. Operators of carbon dioxide pipelines predating the effective date of the final rule (including those transporting carbon dioxide in the supercritical phase in concentrations between 50 and 90 percent carbon dioxide) may choose to meet the more stringent requirements of paragraphs (a) through (c) when designing such pipelines to mitigate the effects of fracture propagation but would not be required to do so.

Valve design is a core consideration in the adequacy and safety of design requirements. Section 195.116 prescribes the minimum design characteristics and capabilities for all valves on part 195-regulated pipelines and requires that all valves be of sound engineering design and undergo hydrostatic shell and seat testing without leakage per Section 11 of ANSI/API Spec 6D. Paragraph (c) requires that each part of the valve that will be in contact with the transported product(s) be compatible with the product(s).

Non-steel components that are part of the valve trim, such as gaskets, have different chemical properties than the main valve body. Hydrogen sulfide, a common contaminant in both carbon dioxide and hazardous liquid product streams, is corrosive and can degrade non-compatible materials. Thus, it is prudent that all parts of valves that are in contact with the product stream be designed for compatibility with the entirety of the product stream, not solely the main commodity being transported. Non-compatibility can result in product leakage, which can harm the environment or persons in the area.

In this rulemaking, PHMSA proposes to expand § 195.116(c) to require compatibility with the entirety of the product stream, which could include non-predominant constituents, meaning products that do not make up the majority of the product stream, and contaminants, such as hydrogen sulfide or water. This proposal would be applicable to pipelines transporting carbon dioxide or hazardous liquids, as all part 195-regulated pipelines can contain minor commodity products or contaminants within their product streams.

PHMSA expects the proposed amendments to the above design requirements would be reasonable, technically feasible, cost-effective, and practicable for affected carbon dioxide pipelines. The proposed enhancements at § 195.111 in particular are incremental improvements on longstanding (quarter-century-old) regulatory language. However, this high-level regulatory language does not account for improvements in understanding the significance of fracture failure and propagation mechanisms on carbon dioxide pipelines since the time of their inclusion in the PSR. Recent industry standards and technical documentation for carbon dioxide pipelines underscore the need for robust, conservative design features to minimize the risk of fracture and fracture propagation.[119] Those resources uniformly recommend the use of materials with demonstrated resistance to fracture initiation and propagation and the use of crack arrestors—precisely the requirements PHMSA proposes in this rulemaking. Unsurprisingly, PHMSA has observed that several recent carbon dioxide pipeline greenfield projects have voluntarily committed to adopting the sort of measures (including detailed analyses of fracture resistance and use of crack arrestors) proposed[120]—demonstrating that these measures proposed to minimize fractures and fracture propagation are the sort that reasonably prudent operators of carbon dioxide pipelines would undertake in ordinary course given the potential lost commercial value and hazards to public safety and the environment from releases from their pipeline projects. In

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[119] See, e.g., Det Norske Veritas, "DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines," at pp. 53 (Sept. 2021); PRCI, Pipeline Transportation of CO_2 SOTA, Gap Analysis and Future Project Roadmap at pp. 1, 133 (Nov. 2023)

[120] See, e.g., Navigator, S.D. Pub. Util. Comm. Doc. No. HP22-002, "Application for Permit to Construct the Navigator Heartland Greenway Project in South Dakota" at Exhibit D (Sept. 27, 2022); Wolf Carbon Solutions, IL Commerce Comm. Doc. No. 23-0475, "Direct Testimony of Patrick Brierley for the Mt. Simon Project" at Exhibit 3.2 (June 16, 2023). Further, operators whose carbon dioxide pipelines "could affect" an HCA may also be able to integrate within their § 195.452-compliant IM plans any of their efforts in complying with proposed amendments at § 195.111.

addition, to facilitate operators' implementation of its proposed revisions at § 195.111, PHMSA is leveraging the well-understood, industry standard-derived regulatory requirements at § 192.620 governing alternative MAOPs for gas pipelines; some of these operators may themselves be among the entities considering new carbon dioxide pipelines that would be subject to the proposed amendments at § 195.111. Also, should an operator identify a compelling need for regulatory flexibility from its proposed amendments at § 195.111, the PSR provides for special permit procedures at § 190.341 to request a deviation from those requirements.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed amendments at § 195.111 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 believes its proposed compliance timeline (based on an effective date of the proposed requirements one year after the publication date of a final rule—which would necessarily be in addition to the time since issuance of this NPRM) would provide affected operators (specifically, carbon dioxide pipelines that are newly constructed, replaced, otherwise changed, or converted to part 195 service) ample time to manage any related compliance costs and implementation challenges as they undertake their projects.

2. Leak Detection Systems for Carbon Dioxide Pipelines—§§ 195.134 and 195.444

CPM systems are algorithmic monitoring tools used by pipeline operators to enhance their ability to recognize hydraulic anomalies on pipelines that may indicate a release of product. CPM systems are used for leak detection purposes and can vary in sensitivity, reliability, accuracy, and robustness performance measures. On liquid pipelines, API RP 1130 is the most widely used industry recommended practice related to CPM leak detection systems. CPM systems can include line balance methods, real-time transient models, pressure and flow monitoring, acoustic and negative pressure wave monitoring, and statistical analysis. CPM systems are not one-size-fits-all; varying types of CPM systems or combinations of CPM systems may be better suited to different operating conditions and pipeline configurations. An ideal CPM leak detection system has a high sensitivity to leaks, timely detection of leaks, accurate alarms, and a robust and reliable algorithm.

PHMSA established base requirements for leak detection systems on pipelines transporting hazardous liquids in a single phase (without gas in the liquid) in a 1998 final rule by adding §§ 195.134 and 195.444 to the PSR and incorporating by reference API RP 1130.[121] When first added in 1998, § 195.134—which falls under the design requirements of subpart C—required the design of new or replaced CPM leak detection systems to comply with section 4.2 of API RP 1130, which contains considerations for selecting a CPM leak detection system with desirable features and functionality, as well as performance metrics for such a system. When first added to the PSR in 1998, § 195.444—which falls under the operation and maintenance requirements of subpart F—required each CPM leak detection system to comply with API RP 1130 in operating, maintaining, testing, record keeping, and dispatcher training of the system. Notably, when first added to the PSR in 1998, neither of these sections explicitly required leak detection systems of any kind, including CPM leak detection systems, on any part 195-regulated

[121] 63 FR 36373, "Pipeline Safety: Incorporation by Reference of Industry Standard on Leak Detection," (July 6, 1998).

pipelines, only requiring that if an operator did install or replace part of a CPM leak detection system, such a CPM leak detection system must comply with API RP 1130.[122]

The 2000 final rule that established IM on part 195-regulated pipelines (2000 IM final rule)[123] required leak detection systems on hazardous liquid and carbon dioxide pipeline systems to protect HCAs. This requirement was included in the 2000 IM final rule on the recommendation of the LPAC, which unanimously recommended RSPA require leak detection capability as part of IM. Within subpart F, § 195.452(i)(3) requires that operators have a means to detect leaks on their pipeline systems, evaluate the capability of those leak detection systems, and modify those leak detection systems as necessary to protect HCAs. At a minimum, an operator's evaluation of their leak detection system must consider the length and size of the pipeline, the type of product carried, the pipeline's proximity to an HCA, the swiftness of leak detection, the location of nearest response personnel, the pipeline's leak history, and the operator's risk assessment results. While the operator may choose to use a CPM leak detection system to meet the requirements of § 195.452(i)(3), they are not required to do so and may instead choose an alternate leak detection system.

In a 2019 final rule on hazardous liquid pipeline safety (2019 final rule),[124] PHMSA modified § 195.134 to require operators on pipelines transporting hazardous liquids in a single

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[122] The edition of API RP 1130 incorporated by reference in the PSR was updated to the 3rd edition in a 2015 final rule on technical standards updates: 80 FR 168, "Pipeline Safety: Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments," (January 5, 2015). At that time, references in §§ 195.134 and 195.444 to API RP 1130 were updated in the PSR from "API 1130" to "API RP 1130."
[123] 65 FR 75377, "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline)," (December 1, 2000).
[124] 84 FR 52260, "Pipeline Safety: Safety of Hazardous Liquid Pipelines," (October 1, 2019).

phase (no gas in the liquid) to have leak detection systems compliant with § 195.444. Hazardous liquid pipelines constructed before the publication date of the 2019 final rule (October 1, 2019) are required to have a leak detection system meeting these requirements by October 1, 2024. Hazardous liquid pipelines constructed after October 1, 2019, were required to have a leak detection system meeting these requirements by October 1, 2020. As that date has since passed, all new pipelines transporting hazardous liquids without gas in the liquid stream are required to have a leak detection system meeting the requirements of §§ 195.134 and 195.444 when placed in service. The existing requirement at § 195.134 for operators of hazardous liquid pipelines to comply with section 4.2 of API RP 1130 in the design of new or replaced CPM leak detection systems was retained. Offshore gathering and regulated rural gathering pipelines are excluded from the requirements of § 195.134.

The 2019 final rule also modified § 195.444 to require operators on pipelines transporting hazardous liquids in a single phase (no gas in the liquid) to have effective leak detection systems compliant with §§ 195.134 and 195.452, as appropriate. Hazardous liquid pipeline operators are required to evaluate the capability of their leak detection systems to protect the public, property, and the environment, and modify them as necessary to do so. At a minimum, these evaluations must consider the length and size of the pipeline, type of product carried, swiftness of leak detection, location of nearest response personnel, and leak history. The preexisting requirement at § 195.444 for hazardous liquids operators to follow API RP 1130 in operating, maintaining, testing, record keeping, and dispatcher training for CPM leak detection systems was retained. Offshore gathering and regulated rural gathering pipelines remain excluded from the requirements of § 195.444.

As previously discussed in this section of the NPRM, under the current PSR, an operator may choose to use a CPM leak detection system to meet the requirements of §§ 195.134, 195.444, and 195.452(i)(3). Operators are not required to do so and may instead choose an alternate leak detection system meeting the requirements of the applicable sections. However, if an operator chooses to use a CPM leak detection system as their method of leak detection, it must also meet the requirements of §§ 195.134(c) and 195.444(c).

PHMSA received a number of comments when developing the 2019 final rule in support of extending leak detection requirements to all part 195-regulated pipelines, except for rural gathering lines. In a joint comment from API and AOPL,[125] they noted their "support [for] expanding leak detection capability evaluations to all pipelines currently subject to regulation under 49 CFR Part 195, except rural gathering lines." In this comment, API and AOPL also noted that CPM is "an effective technology for operators to utilize in their leak detection strategies."[126] Notably at the time of those comments, carbon dioxide pipelines were subject to regulation under part 195 when transporting carbon dioxide in the supercritical phase in concentrations greater than 90 percent.

PHMSA commissioned a 2012 report[127] evaluating operational experience, utility, feasibility of integration on existing pipelines, and cost-effectiveness of leak detection systems on part 192-regulated gas and part 195-regulated hazardous liquids (as well as carbon dioxide

[125] https://www.regulations.gov/comment/PHMSA-2010-0229-0017

[126] Operator TransCanada Keystone Pipeline, LP concurred with these comments in their submission. https://www.regulations.gov/comment/PHMSA-2010-0229-0027

[127] Kiefner and Associates, Inc., "Leak Detection Study – DTPH56-11-D000001," (December 10, 2012), https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/technical-resources/pipeline/16691/leak-detection-study.pdf.

pipelines) produced by Kiefner and Associates, Inc. (Kiefner). The Kiefner report noted that a "leak detection system is the first line of defense in reducing [a leak's] impact" and found that integration of leak detection systems, including CPM leak detection systems, on existing pipelines was generally technically feasible and cost-effective given the existing requirement at § 195.446 for operators to have a supervisory control and data acquisition (SCADA) system that could provide inputs to a CPM leak detection system. Additionally, PHMSA's review of accident data yields that 49 (87.5 percent) of the 56 accidents reported by carbon dioxide operators between 2013 and 2022 involved leaks.[128] Forty two of those accident reports pointed to causes that could have degraded over time, suggesting that earlier leak detection would have resulted in potential avoidance of leak degradation, which ultimately resulted in reportable accidents.

As discussed in Section II.A of this NPRM, carbon dioxide is denser than air at atmospheric pressure and asphyxiating for people and animals; carbon dioxide is also a GHG and contributes to global climate change. Additionally, other constituents in a carbon dioxide product stream may themselves be hazardous to public safety and the environment or (due to their corrosive properties) further degrade any leak. Leaks from carbon dioxide pipelines also entail a risk of brittle fracture at the leak location due to the rapid temperature drop when carbon dioxide depressurizes upon release, thereby increasing the possibility that a leak can degrade.

For these reasons, PHMSA proposes to require leak detection systems on carbon dioxide pipelines. PHMSA proposes modifications at § 195.134 to require leak detection systems on

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[128] *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data*

pipelines transporting carbon dioxide, including supercritical-, liquid-, and gas-phase carbon dioxide. As proposed, carbon dioxide pipelines constructed, replaced, relocated, otherwise changed, or converted to service pursuant to § 195.5 prior to the effective date of a final rule following this NPRM would have 4 years from that effective date to have a leak detection system meeting the requirements of § 195.444. As proposed, carbon dioxide pipelines constructed, replaced, relocated, otherwise changed, or converted to service pursuant to § 195.5 on or after the effective date of a final rule would need (by that effective date) a leak detection system meeting the requirements of § 195.444. In addition, PHMSA proposes that carbon dioxide pipelines transporting either supercritical- or liquid-phase carbon dioxide would be required to install and use CPM leak detection systems.

Conforming changes are also proposed at paragraphs (a) and (c) of § 195.444 to reflect the inclusion of carbon dioxide pipelines in the leak detection system requirements. No other changes are proposed in these sections aside from the addition of carbon dioxide pipelines to the list of pipelines for which a leak detection system is required; this includes retaining the preexisting exclusion of offshore gathering and regulated rural gathering pipelines from the requirements of §§ 195.134 and 195.444, as well as retaining the incorporation by reference of API RP 1130. Additionally, this proposal would require that, if pipeline operators use a CPM leak detection system, those systems would be required to comply with requirements at §§ 195.134(c) and 195.444(c).

PHMSA expects the proposed amendments to require leak detection systems would be reasonable, technically feasible, cost-effective, and practicable improvements to existing PSR requirements for carbon dioxide operators. Some existing carbon dioxide pipeline operators must already have leak detection systems, as § 195.452(i)(3) explicitly requires them on new and existing carbon dioxide pipelines that could affect an HCA. For other new and existing carbon dioxide pipelines, leak detection systems would be able to leverage operational data and information obtained from SCADA systems already required by § 195.446(a). For example, the CPM systems PHMSA proposes for all supercritical- and liquid-phase carbon dioxide pipelines would generally consist of incremental computer software and hardware upgrades for pre-existing SCADA systems. Although some operators transporting gas and liquid carbon dioxide will likely already have CPM systems absent the proposed rule, PHMSA conservatively assumes in the PRIA that all operators transporting gas and liquid carbon dioxide would incur incremental costs associated with upgrading their leak detection systems to a coupled SCADA-CPM system; PHMSA seeks comment on this assumption, specifically, on whether it is overly conservative. Within the minimum requirements for a CPM system set out at § 195.444, PHMSA expects operators would have discretion to choose from a variety of CPM leak detection systems based on their specific financial and technical constraints. Indeed, the limited technical challenges and relatively low cost of CPM and other leak detection systems featured prominently in the Kiefner report's assessment that integration of those systems would generally be a cost-effective approach to minimize release volumes from new and existing part 195-regulated pipelines (including supercritical-phase carbon dioxide pipelines). Unsurprisingly, PHMSA has observed that several recent carbon dioxide pipeline greenfield projects have voluntarily committed to adopt leak detection systems (including CPM systems) proposed[129]—demonstrating that those

[129] See, e.g., Navigator, S.D. Pub. Util. Comm. Doc. No. HP22-002, "Application for Permit to Construct the Navigator Heartland Greenway Project in South Dakota" at Exhibit D (Sept. 27, 2022); Wolf Carbon Solutions, IL Commerce Comm. Doc. No. 23-0475, "Direct Testimony of Patrick Brierley for the Mt. Simon Project" at Exhibit 3.2 (June 16, 2023).

measures are the sort that reasonably prudent operators of carbon dioxide pipelines would undertake in ordinary course given the potential lost commercial value and hazards to public safety and the environment from releases from their pipelines. Should an operator identify a compelling need for regulatory flexibility from this proposed requirement, the PSR provides for special permit procedures at § 190.341 to request a deviation.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 believes that operator compliance timelines—based on an effective date of the proposed requirement (one year after the effective date of a final rule, which timeline would necessarily be in addition to the time since issuance of this NPRM) would provide operators ample time to implement requisite systems and manage any related compliance costs.

3. Additional Pipeline Requirements Based on Location—§ 195.210

In accordance with 49 U.S.C. 60104(e), PHMSA is not authorized to prescribe the location or the routing of a pipeline facility; however, the Pipeline Safety Laws contemplate that PHMSA may prescribe requirements as necessary to protect public safety and the environment following a pipeline operator's decision-making regarding the location of their facilities.[130] For example, the PSR at part 192 exercises this authority by requiring gas pipeline operators who

[130] The examples in parts 192 and 195 provided in this section III.C.3 discussion are not exhaustive; many of PHMSA's safety requirements in those parts depend to some degree on the location of a pipeline.

select rights-of-way within 100 yards (91 meters or 300 feet) of either a building or small, well-defined outside area meeting certain occupancy requirements to comply with more stringent design, construction, testing, operations, maintenance, inspection, and repair requirements. (See §§ 192.105, 192.111, 192.179, 192.243, 192.503, 192.624, 192.634, 192.705, 192.706, 192.710 and 192.714.) In part 195, § 195.210 has long contained minimum safety-focused requirements that inform operators' decision-making regarding (rather than prescribe) the precise the location of hazardous liquid and carbon dioxide pipelines. That provision requires operators to select pipeline rights-of-way to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. That provision at § 195.210(b) also requires operators to provide at least 12 inches (305 millimeters) of cover in addition to that prescribed at § 195.248 on any pipeline that is installed within 50 feet (15 meters) of any private dwelling, or any industrial buildings or place of public assembly in which persons work, congregate, or assemble.

Apart from those generically applicable, location-based, prescriptive requirements, PHMSA also addresses location-based public safety risks associated with releases of gas through its IM requirements. Specifically, part 192 regulations for determining if a gas pipeline is in an HCA (and therefore subject to part 192, subpart O IM requirements) make use of criteria at § 192.903 incorporating a mathematical equation for calculating the likely area (the "potential impact circle" or "potential impact radius") in which the potential failure of a gas pipeline could have significant impacts on people or property. This calculated potential impact radius is used to help operators identify HCAs, within which more frequent inspection and other preventive and mitigative measures are performed, to reduce the likelihood and consequence of a gas pipeline failure. The mathematical equation used to calculate the potential impact radius is based principally on the thermal radiation hazard associated with the release of flammable gas in a pipeline rupture and subsequent ignition of the released gas.[131,132] Part 195 IM regulations (at § 195.450, et seq.) likewise provide location-based, enhanced requirements addressing public and environmental safety risks from releases of carbon dioxide and hazardous liquid pipelines that could affect an HCA, particularly on pipelines transporting those hazardous liquids that can persist in the environment for long periods after release.[133]

In contrast, carbon dioxide behaves differently when released to the atmosphere compared to flammable gases and hazardous liquids.[134] Specifically, when modeling the failure and subsequent release of carbon dioxide from a pipeline compared to a failure and release of (flammable) natural gas, release simulations indicate that a significantly larger percentage of the initial mass in the pipeline will be immediately released from a rupture on a carbon dioxide pipeline than the percentage of the initial mass in the pipeline that would be released from a natural gas pipeline.[135] This increased amount of released carbon dioxide, combined with a density greater than air, can quickly lead to asphyxiating concentrations of carbon dioxide at or near the ground level. Further, these hazardous plumes of carbon dioxide can settle into low-lying areas and flow downhill into areas that are distant from the release site, before ultimately

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[131] "OPS TTO14 – Derivation of Potential Impact Radius Formulae for Vapor Cloud Dispersion" (Baker, 2005)
[132] "A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines" (Stephens 2000).
[133] See PHMSA, "Final Rule: Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline)," 65 FR 75378, 75379, 75390-92 (Dec. 1, 2000).
[134] As explained in section II.B above, as CCUS infrastructure expands the potential public safety and environmental risks associated with releases from carbon dioxide pipelines may increase as more hazardous substances are entrained in the product stream. Some of those substances may remain within the carbon dioxide vapor for some portion of its migration from the release point to surrounding areas, potentially resulting in public safety and environmental risks supplementing any asphyxiation risk.
[135] Mahgerefteh et al, "Pressurised CO_2 Pipeline Rupture" (January 2008)

dissipating into the atmosphere. Unlike other gases (e.g., natural gas and certain other part 192-regulated gases) whose release could result in ignition or combustion in the immediate vicinity of the release point (thereby potentially limiting the geographic scope of public safety and environmental harms), carbon dioxide is not a flammable gas. Combustion or ignition would not reduce the potential for carbon dioxide asphyxiation hazards distant from the release site, nor would the asphyxiation hazard posed by released carbon dioxide persist in the environment as long as other part 195-regulated commodities (e.g., crude oil); released carbon dioxide eventually dissipates to atmosphere.[136] Reliance on either of the above approaches currently used by PHMSA's parts 192 and 195 regulations may not, therefore, be appropriate to address the asphyxiation and other risks specific to carbon dioxide pipelines.

The risks carbon dioxide pipelines pose to the public and the environment are not adequately addressed in existing location-based part 195 requirements. Therefore, PHMSA is proposing additional safety measures for onshore, newly constructed, relocated, replaced, or otherwise changed (or newly converted to part 195 service) pipelines transporting carbon dioxide located within 2 miles of any residence, business, or place of public assembly. First, those operators would be required to retain documentation supporting their decision to position the pipeline at that location. Second, operators of onshore carbon dioxide pipelines would be required to perform a population density survey to understand and catalog the locations and needs of affected entities (including, but not limited to, the general public) that are located within an emergency planning zone (two miles on either side of the pipeline) to inform their pre-

[136] See PHMSA, "Final Rule: Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline)," 65 FR 75378, 75379, 75390-92 (Dec. 1, 2000).

emergency public awareness initiatives and facilitate emergency response efforts in the event of an emergency on the pipeline. Third, those operators would be required—before the pipeline begins operations—to distribute emergency response information to every building intended for human occupancy and place of public assembly within the two-mile emergency planning zone. Fourth, within the emergency response information distributed to buildings and places of public assembly that the operator has determined are in locations that could be affected by a carbon dioxide pipeline release (pursuant to the vapor dispersion analysis performed at § 195.452(f)(1) or the default, 2-mile distance at § 195.456, as discussed in section III.G.1), the operator must include an explicit notification of such a determination and identify specific precautions members of the public can take in the event of an emergency. These proposed location-based, enhanced requirements at § 195.210 would complement proposals elsewhere in this NPRM (see section III.F.3) enhancing § 195.402 emergency response planning requirements by (1) adding a new § 195.402(c)(17) that would require operators of all carbon dioxide pipelines—both new and existing—to obtain (if not performed during construction or conversion as proposed at § 195.210) and periodically update this population density survey when developing and updating the two-mile emergency planning zone around their pipelines; and (2) adding a new § 195.402(e)(9) to provide automatic notifications to the public informing them when an emergency has occurred and what specific steps the public should take based on the known circumstances of the emergency.

The additional safety measures described above would encourage carbon dioxide pipeline operators to select rights-of-way in a manner that mitigates consequences to public safety and the environment in the event of a release. The additional proposed regulatory obligations (including the proposed 2-mile emergency planning zone, annual population density survey, emergency response information distribution, and siting decision-making documentation requirements) would reinforce the existing, broad language at § 195.210(a) directing all part 195-regulated operators of new carbon dioxide and hazardous liquid pipelines to consider public safety consequences arising from their siting decisions by identifying new, concrete regulatory obligations that would attach to such decisions. Meanwhile, as explained further in section III.F.3 below, PHMSA's emergency response information distribution requirements will help ensure that members of the community most at risk in the event of a release from a carbon dioxide pipeline (those within the emergency planning zone) will have, in advance of an emergency, the information needed to take prompt, appropriate precautionary measures (e.g., evacuation) to protect themselves and their families, rather than wait for instructions from emergency response personnel, who may also have to perform any number of other response actions (e.g., stopping the release, investigating its extent, etc.) in the critical early moments of a pipeline emergency. PHMSA further proposes to explicitly require that operators of newly constructed, relocated, replaced, or otherwise changed (or newly converted to part 195 service) carbon dioxide pipelines ensure that their efforts implementing the proposed § 195.210(c) emergency response information distribution requirements align with the existing public awareness program communication requirements in applicable portions of § 195.440; this provision in turn references longstanding consensus industry guidance on pipeline public awareness programs in API RP 1162.[137] Additionally, PHMSA's proposed initial population density survey (§ 195.210(c)) and annual update (§ 195.402(c)(17)) requirements

[137] Applicable provisions within § 195.440 would include paragraphs (e), (f), (g), (i), the introductory text of paragraph (d), and subparagraphs (d)(2), (d)(3), (d)(4), and (d)(5).

would ensure that safety-critical information is up-to-date and can be distributed to the persons who need that information in a manner accessible to them.

PHMSA also proposes at § 195.210(c) and at § 195.402(c)(17) and (e)(9) a 2-mile emergency planning zone to manage the location-based risks to public safety from emergencies on carbon dioxide pipelines. As explained in sections II.A and B above, releases from carbon dioxide pipelines can result in asphyxiation (and potentially other) public safety hazards a significant distance from the release point. Precisely how far those hazards from the release point those could occur turns on a number of variables, including pipeline segment-specific operating parameters (diameter, operating pressure, etc.); release characteristics; topography of the surrounding landscape; environmental conditions (e.g., wind, humidity, and temperature); and the diverse physical distributions of private dwellings, industrial buildings, and places of public assembly in the vicinity of the pipeline.[138] PHMSA has therefore proposed at § 195.210(c) a single, uniform, emergency planning zone of 2 miles in either direction from the centerline of each carbon dioxide pipeline segment. PHMSA expects this approach would promote efficient administration of proposed population density survey and emergency response information distribution requirements by PHMSA and State pipeline safety regulatory authorities, as well as the operators themselves. Also, the proposed 2-mile boundary is informed by modeling data and

[138] PHMSA acknowledges that the 2-mile emergency planning zone boundary it is proposing at § 195.210(c) to manage location-based public safety risks may not always be consistent with the geographic scope of HCAs which "could [be] affected" pursuant to PHMSA's proposed amendments to its IM regulations at §§ 195.452 and 195.456. PHMSA affirms that any difference reflects the different objects and means of those two elements of the PSR: whereas § 195.210(c) imposes generic emergency response-pertinent requirements protecting any person who may live, work or assemble in areas surrounding a carbon dioxide pipeline, §§ 195.452 and 195.456 impose a suite of more burdensome regulatory requirements directed toward minimizing risks within areas designated in regulation as "high-consequence areas" due to their population density or characteristics.

operators' own evaluations of the geographic scope of the hazards from release of carbon dioxide pipelines, supplemented by reasonable conservatism (accounting for variability across the spectrum of potential carbon dioxide pipeline operating characteristics, topography, and environmental conditions). For example, air testing several hours after the Satartia accident yielded concentrations of carbon dioxide approaching NIOSH's 30,000 ppm short-term carbon dioxide in buildings more than a mile from the release point. Similarly, computational fluid dynamics modeling[139] performed to calculate gas dispersion from ruptures on carbon dioxide pipelines estimates that the vapor cloud from a supercritical-phase, 6-inch pipeline could cause carbon dioxide concentrations at the IDLH threshold of 40,000 ppm nearly a half-mile from the release point. This suggests that vapor clouds could induce carbon dioxide concentration levels (1) at or above the IDLH threshold at greater distances in the event of a rupture from pipelines with nominal diameter greater than 6 inches, and (2) at or above other OSHA or NIOSH thresholds for carbon dioxide (discussed in section II.A). Further, the real-world measurements after the Satartia accident and these described academic modeling efforts are consistent with operator-projected vapor dispersion and overland spread analyses modeling, which yield concentrations of carbon dioxide exceeding NIOSH's 30,000 ppm short-term carbon dioxide exposure limit about 2 miles from release points following a rupture of a large (greater than or equal to 20-inch outer diameter) carbon dioxide pipeline. Given the above modeling and real-world data speaking to the variability in the geographic limit of public safety hazards associated with releases from carbon dioxide pipelines, PHMSA understands its choice of a uniform, 2-mile

[139] See, e.g., CFD, "Modelling of Gas Dispersion from a Ruptured Supercritical CO_2 Pipeline," (Mar. 2011), http://www.cham.co.uk/casestudies/CCS_Gas_Dispersion.pdf (last visited Oct. 5, 2023).

emergency planning zone proposed at § 195.210(c) strikes an appropriate, evidence-based balance between administrative efficiency, operator compliance burdens, and public safety.

Lastly, PHMSA proposes clarifications at paragraphs (a) and (b) of § 195.210 and a change to the section title to reduce confusion among operators and the public of the requirements of § 195.210. PHMSA has proposed retitling § 195.210 to "Proximity to residences and other places" to better clarify the scope. Paragraph 195.210(a) directs operators of new carbon dioxide and hazardous liquid pipelines to select pipeline rights-of-way to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. PHMSA has taken the meaning of "private dwellings" to be equivalent with "residences" and "industrial buildings" to be equivalent with "businesses." The Plain Language Act of 2010[140] dictates that Federal agencies use familiar, short words wherever possible; thus, PHMSA has proposed replacing "private dwellings" with the more commonly used term "residences" and "industrial buildings" with the more commonly used term "businesses" throughout § 195.210(a) and (b). Lastly, PHMSA has proposed clerical edits at § 195.210(b) to use the active voice, which is also consistent with the requirements of the Plain Language Act of 2010.

PHMSA expects the proposed amendments to location-based requirements at § 195.210 would be reasonable, technically feasible, cost-effective, and practicable for affected operators of onshore newly constructed, relocated, replaced, otherwise changed, or converted carbon dioxide pipelines. The proposal for those operators to document decision-making on their choice of

[140] Pub. Law 111-274, H.R. 946, "Plain Writing Act of 2010," (October 13, 2010). U.S. General Services Administration, "Federal Plain Language Guidelines," (May 2011).

location would be an incremental improvement of the longstanding requirement at § 195.210(a) admonishing operators to site their facilities so as to minimize proximity to inhabited areas. Operators can use publicly available data and tools, such as the National Energy Technology Laboratory's CCS Pipeline Route Planning Database, to aid in choosing locations to minimize proximity to inhabited areas.[141] For carbon dioxide pipelines for which such avoidance is impracticable, PHMSA's proposed population density survey requirements are consistent with industry guidance emphasizing that operators themselves need to perform population density surveys along pipeline rights of way and notify affected stakeholders of the risks from a release from those facilities.[142] Further, the contact and other information operators would need to collect from stakeholders to comply with these proposed requirements has been narrowly-drawn to the minimum data needed to ensure meaningful public awareness of safety risks before an emergency, while also ensuring any notifications are timely and effective during an emergency. Operators' compliance efforts could also be integrated with their approaches for compliance with existing IM program requirements at § 195.452 and public awareness requirements at § 195.440 (which itself adopts consensus industry guidance within API RP 1162). For example, existing regulations at § 195.440 require carbon dioxide pipeline operators to develop comprehensive public awareness programs to educate stakeholders (in English and other languages as necessary)

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[141] National Energy Technology Laboratory, CCS Pipeline Routing Database, *https://edx.netl.doe.gov/dataset/ccs-pipeline-route-planning-database-v1*.

[142]"Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document; Guidelines for Preparedness and Initial Response to a Pipeline Release of Carbon Dioxide (CO_2)", API, Liquid Energy Pipeline Association, and National Association of State Fire Marshals; (August 2023) pp. 6, 17; Det Norske Veritas (DNV), DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines at p.40 (Sept. 2021).

of the possible hazards associated with unintentional releases and the steps they would need to take during an emergency. Additionally, should an operator of any pipeline subject to § 195.210 identify a need for regulatory flexibility from this proposed requirement, the PSR provides for special permit procedures at § 190.341 to request a deviation. Also, proposals at § 195.210(a) and (b) and the proposed re-title of § 195.210 are merely clerical edits that clarify the section's preexisting intent and scope and comply with Federal requirements on the use of plain language.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed amendments at § 195.210 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 believes that its proposed compliance timeline (based on an effective date of the proposed requirements one year after the publication date of a final rule—which would necessarily be in addition to the time since issuance of this NPRM) would provide affected operators (specifically, only carbon dioxide pipelines that are newly constructed, replaced, relocated, otherwise changed, or converted to part 195 service) ample time to manage any related compliance costs and implementation challenges as they undertake their projects.

4. Addition of Depth of Cover Requirement for Agricultural Areas—§ 195.248

Section 195.248 contains the minimum requirements for the depth of cover of buried pipelines. Depth of cover refers to the measured distance between the top of the pipe and the ground level, roadbed, river bottom, or underwater natural bottom, as applicable. Depth of cover is a primary mechanism for the prevention of outside force damage to buried pipelines, including third party damage from excavation and loads from heavy machinery.

Paragraph (a) of § 195.248 requires that all pipelines must be buried below the level of cultivation, with certain exceptions contained at paragraph (b). Paragraph (a) also contains a table with the required depth of cover based on the location of the area where the pipe is buried. These locations are: industrial, commercial, and residential areas; crossing of inland bodies of water with a width of at least 100 feet from high water mark to high water mark; drainage ditches at public roads and railroads; deep water port safety zones; Gulf of Mexico and its inlets in waters less than 15 feet deep as measured from mean low water; other offshore areas under water less than 12 ft deep as measured from mean low water; and any other area. For each location, a proposed minimum depth of cover is listed for both normal excavation and rock excavation conditions at the time of burial. Depth of cover is the same regardless of product transported, as the product transported does not affect the likelihood of an outside force, including excavation equipment, damaging the pipeline.

Commercial and private farming activities often use heavy machinery to cultivate the soil and perform other relevant activities. Depending on the size of the farming operation and machinery function this equipment can weigh upwards of 45,000 pounds.[143] Heavy machinery used for tillage such as tractor-mounted rippers can excavate at depths "as great as 4 to 5 ft (1.2 to 1.5 m) and range from 10 to 30 in. (0.25 to 0.75 m) on machines of the D7 class and smaller."[144]

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[143] John Deere, S790 Specifications, (Accessed July 19, 2023).
[144] Paul V. Sellmann and Dale R. Hill, Cold Regions Research and Engineering Laboratory, Department of Defense, "Ripping Frozen Ground with an Attachment for Dozers," June 1997.

Industry standards on depth of cover contained in American Society of Mechanical Engineers (ASME) B31.4-2006, a document incorporated by reference at § 195.3, state that "buried pipelines shall be installed below the normal level of cultivation and with a minimum cover not less than that shown in Table 434.6(a)."[145] Table 434.6(a) contains the location of "Cultivated, agricultural areas where plowing or subsurface ripping is common" with a minimum depth of cover of 48 inches (1.2 meters) in normal excavation areas. Rock excavation areas requiring blasting or equivalent means of removal are marked as not applicable, which is intuitive for agricultural areas. ASME B31.4-2006 also notes that for agricultural areas, "Pipelines may require deeper burial to avoid damage from deep plowing; the designer is cautioned to account for this possibility."

Section 195.248 does not specify a minimum depth of cover for agricultural areas, allowing operators to bury pipelines at the minimum depth of cover for the "any other areas" location category of 30 inches in normal excavation areas and 18 inches in rock excavation areas, though this depth must be at least the depth of cultivation. This is significantly less than the minimum depth of cover in the industry standards contained in ASME B31.4-2006 and the ripping depth capability of some agricultural equipment, as noted above. As PHMSA noted in a 2008 final rule entitled "Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines," a "greater depth of cover decreases the risk of damage to the pipeline from excavation, including farming operations."[146] PHMSA also noted

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[145] ASME B31.4-2006, incorporated by reference into part 195 at § 195.3.
[146] PHMSA, 73 FR 62147, "Pipeline Safety: Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines," (October 17, 2008).

in that final rule that "pipelines near the surface are more likely to be damaged by surface activities."

This NPRM proposes to enhance § 195.248 by adding a new location category to the table within paragraph (a) for "Agricultural areas" with a minimum depth of cover of 48 inches (1.2 meters) for normal excavation and "N/A," or not applicable, for rock excavation, consistent with ASME B31.4-2006. This location category would be applicable to all part 195-regulated pipelines subject to § 195.248, including carbon dioxide, hazardous liquid, and gathering pipelines to which the section is applicable. PHMSA expects the proposed amendments of depth-of-cover requirements at § 195.248 would be reasonable, technically feasible, cost-effective, and practicable for operators of hazardous liquid and carbon dioxide pipelines that are newly constructed, replaced, otherwise changed, or converted to part 195 service. As explained above, the addition of a specific depth-of-cover requirement for agricultural areas and a new admonition for operators to select even deeper burial to avoid the risk of deep plowing would align PHMSA requirements with the contents of longstanding consensus industry standard ASME B31.4-2006. The 48-inch depth-of-cover for agricultural areas proposed is less than the 60-inch minimum depth of cover that recent dioxide pipeline greenfield projects have voluntarily committed to adopting across their entire length[147]—demonstrating the marginal increase in depth-of-cover proposed here is the sort reasonably prudent operators of carbon dioxide pipelines would undertake in ordinary course given the potential lost commercial value and hazards to public

[147] See, e.g., Navigator, S.D. Pub. Util. Comm. Doc. No. HP22-002, "Application for Permit to Construct the Navigator Heartland Greenway Project in South Dakota" at Exhibit D (Sept. 27, 2022); Wolf Carbon Solutions, IL Commerce Comm. Doc. No. 23-0475, "Direct Testimony of Patrick Brierley for the Mt. Simon Project" at Exhibit 3.2 (June 16, 2023).

safety and the environment from releases from their pipelines. Should an operator of any pipeline subject to § 195.248 identify a compelling need for regulatory flexibility from this proposed requirement, the PSR provides for special permit procedures at § 190.341 to request a deviation.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed amendment at § 195.248 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 believes its proposed compliance timeline (based on an effective date of the proposed requirements one year after the publication date of a final rule—which would necessarily be in addition to the time since issuance of this NPRM) would provide affected operators (specifically, only hazardous liquid and carbon dioxide pipelines that are newly constructed, replaced, relocated, otherwise changed, or converted to part 195 service) ample time to manage any related compliance costs and implementation challenges as they undertake their projects.

5. Addition of Fixed Vapor Detection and Alarm Systems on HVL Pipeline Systems—§§ 195.263 and 195.452(i)(5)

From 2010 through 2022, a total of 848 accidents were reported to PHMSA on carbon dioxide and HVL pipeline systems.[148] Of these accidents, which included events ranging from leaks to ruptures, 460 were due to equipment failure, and 89 were due to incorrect operation, as reported by operators. These accident causes (equipment failure and incorrect operation)

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[148] *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data*

represented the first and third most prevalent accident causes reported on carbon dioxide and HVL pipeline systems during that period, with material failure of the pipe body or weld as the second most prevalent cause. Accidents due to equipment failure and incorrect operations resulted in one employee fatality and one contractor injury (caused by a fire during operations at a receiver to collect a maintenance tool which occurred in 2017 in Paradis, Louisiana). These two accident causes (equipment failure and incorrect operation) also resulted in the release of almost 250,000 barrels of lost product, of which only 423 barrels were recoverable, an unsurprising recovery rate given the highly volatile nature of the transported commodities involved. Of the 549 accidents caused by equipment failure and incorrect operation, 418 were not identified by SCADA systems, and 530 were not detected by CPM systems. Most of these accidents (392 out of 549) were identified by individuals at or near the site, including operator personnel, first responders, or the public. Releases from pipelines transporting carbon dioxide and other HVLs are most likely to occur at facilities where personnel may be present intermittently, including pump or compressor stations, meter stations, valve stations, and other facilities, such as launcher and receiver sites.

Releases from carbon dioxide and HVL pipeline systems present varying risks depending on the product transported and the location of the release relative to population centers and environmental resources. As discussed in section II.A, pipelines transporting carbon dioxide present serious asphyxiation risks to individuals and animals within released vapor clouds, as well as environmental costs from the release of GHGs. Anticipated increases in CCUS applications also present public safety and environmental risks associated with other hazardous constituents in the carbon dioxide product stream—some of which whose presence in the atmosphere following a release may not be readily seen or smelled by personnel (much less recognizable as presenting in hazardous or flammable/combustible concentrations). Similarly, releases of certain HVLs, including anhydrous ammonia and various product streams containing hydrogen sulfide, can also present serious asphyxiation and toxicity risks. While some portion of the released HVL may dissipate into the environment in the immediate vicinity of the release site, some released HVLs can also form dense vapor clouds, similar to carbon dioxide, that can negatively impact operator personnel, the public, and the environment far from the pipeline. Those public safety and environmental hazards are particularly significant when the release from an HVL pipeline occurs in, or could otherwise affect, an HCA as defined at § 195.450. In addition, when release rates exceed the dissipation rate for HVL vapors, including those HVLs with a density less than air, which can occur during a rupture event, vapor clouds can still form in excess of NIOSH IDLH concentrations for asphyxiation and toxicity.[149] An example of this occurred during an accident on an anhydrous ammonia pipeline near Tekamah, Nebraska in 2016.[150] In this accident, an 8-inch pipeline transporting anhydrous ammonia ruptured, causing the formation of an ammonia vapor cloud that took the life of a nearby resident and injured two others.

In addition to the threats of asphyxiation and toxicity, some HVLs present an additional threat not presented by carbon dioxide: flammability/combustibility. When concentrations of released HVLs exceed the lower explosive limit (LEL) of that product, the vapor cloud may ignite, causing a fire or explosion depending on the local conditions. These combustible

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[149] https://www.cdc.gov/niosh/idlh/intridl4.html
[150] NTSB, *Pipeline Accident Brief: Magellan Pipeline Anhydrous Ammonia Release*, PAB-20/01, (January 29, 2020). https://www.ntsb.gov/investigations/AccidentReports/Reports/PAB2001.pdf.

conditions can present real harm to persons in the area, as shown by the 2017 accident in Paradis, Louisiana.[151] In that accident, a flammable concentration of liquified petroleum gas/natural gas liquid ignited during venting operations at a receiver to collect a maintenance tool. This is a routine maintenance activity regularly performed by operations personnel as part of an IM program. Numerous other HVLs also present a flammability/combustibility risk when released, including propane, butane, and ethane.

One tool commonly used in industrial applications to identify hazardous concentrations of carbon dioxide and other HVLs in working environments (as well as provide defense-in-depth to other real-time release monitoring systems) is a fixed vapor detection and alarm system. These systems are currently used in a wide range of industries, including the chemical and petrochemical refining industries, large-scale agricultural operations, chemical feedstock production, small- and large-scale laboratories, and food and beverage production and service industries. Depending on the scale of the facility, vapor detection and alarm systems typically have four main components: (1) sensors capable of detecting hazardous concentrations of vapors in the area; (2) a communication system to relay information from the sensors to other systems; (3) a control center to receive alerts of hazardous concentrations; and (4) warning mechanisms for staff in the area.

Sensors used in fixed vapor detection and alarm systems can detect a wide range of hazardous airborne chemicals that are transported as HVLs in the pipeline, including flammable/combustible gases (including hydrocarbons such as propane), carbon dioxide,

[151] Phillips 66 Pipeline LLC, PHMSA 30-Day Accident Report #20170094, March 10, 2017.

hydrogen sulfide, and ammonia.[152] In fixed vapor detection and alarm systems, the sensors are permanently installed at the facility to continuously monitor for hazardous vapor concentrations of all flammable, asphyxiating, and toxic chemicals that are present in the pipeline stream. These sensors, or vapor detectors, can be used to measure concentrations up to and beyond the LEL for those vapors that are flammable, and up to and beyond the IDLH limits for both asphyxiation and toxicity for vapors that present those threats. Depending on the chemical being monitored, sensor technology can include photoionization detectors, infrared analyzers, and combustible gas monitors. As noted in OSHA's Technical Manual, Section II: Chapter 3, Technical Equipment: On-Site Measurements, sensors should be routinely maintained and calibrated according to the manufacturer's schedule.

As discussed above, leaks from pipelines transporting HVLs are most likely to occur at facilities where personnel may be present intermittently, including pump or compressor stations, meter stations, valve stations, and other facilities (such as launcher and receiver sites for ILI tools, instrumented internal inspection devices, and maintenance activities). Depending on the release rate from the leak and local conditions, personnel entering one of these facilities, whether they are enclosed spaces or not, may unknowingly enter a hazardous situation. For example, if a leak occurred at a meter station transporting carbon dioxide where the concentration in the area exceeded the IDLH, a measurement technician entering the station to perform routine maintenance could rapidly asphyxiate and become seriously injured, as the vapor cloud from the releasing carbon dioxide would not be visible. Likewise, a leak at a receiver facility on a pipeline

[152] OSHA Technical Manual (OTM), Section II: Chapter 3, *Technical Equipment: On-site Measurements*, (February 11, 2014), https://www.osha.gov/otm/section-2-health-hazards/chapter-3#Appendix1InstrumentChart.

transporting a combustible HVL could ignite and cause significant injury to an operations specialist cleaning an ILI receiver; this possible scenario is highly similar to what occurred in 2017 on an HVL pipeline that resulted in one operator fatality and one contractor injury. These types of accidents are preventable through the use of fixed vapor detection and alarm systems, which alert local personnel already working in or about to enter the area of hazardous concentrations through audible and visual alarms. As the system is a fixed system, alarm mechanisms (such as bells, sirens, and flashing lights) are permanently installed at the facility and activate whenever a hazardous concentration is identified by the vapor detection sensors. Operators would be expected to install vapor detection sensors with sufficient capabilities and in adequate numbers and locations to meet the capability requirements of the fixed vapor detection and alarm system described at § 195.263. These warning alarms occur well before levels reach the IDLH (whether asphyxiation or toxicity) or LEL. Additionally, as these systems notify a control center of any received alarms regardless of whether personnel are on site, fixed vapor detection and alarm systems forewarn operator personnel of the situation and allow for informed decision-making and preparation in advance of operator personnel entering the hazardous environment. As shown by the accident data above, SCADA and CPM systems often do not identify leaks on carbon dioxide and HVL pipeline systems prior to personnel working in or near the area or prior to the receipt of notifications of a release from the public or first responders.

In addition to personnel safety, leaks at facilities—including pump or compressor stations, meter stations, valve stations, and other facilities (such as launcher and receiver sites)—

constitute a large volume of released product, as described above.[153] As these sites may or may occupied by personnel, releases can continue for days or weeks before they are identified. As discussed throughout this NPRM, releases of carbon dioxide can contribute to environmental damage through a number of mechanisms, including contributions to climate change. Other HVLs can also cause environmental damage, including contributions to climate change (i.e., release of GHGs from propane and other hydrocarbon-based products) and injury to local animal populations (i.e., asphyxiation of local fauna by anhydrous ammonia). Fixed vapor detection and alarm systems would allow operators to identify and correct these releases faster, resulting in reduced volumes of leaked product and lesser consequences to the environment.

PHMSA, therefore, proposes the addition of a new § 195.263, to require fixed vapor detection and alarm systems on part-195 regulated pipelines transporting HVLs (including gathering lines and pipelines transporting carbon dioxide) that are constructed, replaced, relocated, otherwise changed, or converted to service on or after the effective date of a final rule at all pump stations, compressor stations, meter stations, and valve stations (to include launching and receiving facilities for ILI tools, instrumented internal inspection devices, and maintenance activities). PHMSA proposes at § 195.452(i)(5) an analogous requirement for some existing HVL pipelines—namely, those representing the highest risks to public safety and the environment because they have a pump station, compressor station, meter station, or valve station (including facilities for launching and receiving in-line inspection tools or instrumented internal inspection devices)—that are located in or could affect an HCA.

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[153] *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data*

Each fixed vapor detection and alarm system will be required to perform four functions: (1) detect the HVL product and any hazardous (flammable, combustible, toxic, or asphyxiating) constituents in the product stream; (2) continuously monitor for concentrations above (a) 25 percent of the LEL for flammable/combustible constituents and (b) 25 percent of the NIOSH IDLH for asphyxiating or toxic constituents, whichever is lower; (3) notify personnel in the area with audible and visual alarms; and (4) notify personnel in an operational control center of the alarm.

Vapor detection equipment should be capable of identifying any flammable, combustible, asphyxiating, or toxic constituents present in the product stream. This may include minor constituents such as hydrogen sulfide, in addition to the transported product. For flammable constituents, sensors must be capable of detecting concentrations above 25 percent of the LEL for that chemical. For constituents that may asphyxiate or intoxicate, sensors must be capable of detecting concentrations above 25 percent of the NIOSH IDLH for asphyxiation or toxicity, whichever is the lower concentration. PHMSA has selected the 25 percent of LEL threshold for flammable or combustible constituents based on the current threshold at § 192.736 for combustible gas detection at compressor stations; that threshold was adopted by RSPA on the recommendation of industry stakeholders based on its widespread use in the natural gas and

LNG industries to ensure adequate safety margins from ignition.[154] PHMSA similarly affirms that a threshold of 25 percent of pertinent NIOSH IDLH limits for asphyxiating or toxic constituents is an appropriately conservative safeguard of public safety. As noted in section II.A. above, the IDLH values are acute, short-term exposure limits ensuring protection against concentrations NIOSH has determined are "likely to cause death or immediate or delayed permanent adverse health effects," but those thresholds exist on a scale of (lower) concentration and (longer) exposure duration thresholds, each of which correlate to significant adverse health effects. PHMSA's choice of a 25 percent threshold tied to the NIOSH ILDH thresholds, therefore, provides maximum assurance that operator personnel and other individuals will avoid exposure to hazardous constituents in concentrations likely to result in catastrophic adverse health effects (NIOSH IDLH), while still ensuring protection against other serious health hazards (other NIOSH and OSHA exposure thresholds) at lower concentrations and for various durations.

Notification methods for alarms for personnel must include both audible and visual methods, which can consist of bells, sirens, flashing lights, and other appropriate and sufficiently detectable signals to personnel entering or already inside the area. Lastly, the notified operational control center may be a personnel occupied compressor station or pump station building (not

[154] See RSPA, "Final Rule: Gas Detection and Monitoring in Compressor Station Buildings," 58 FR 48460, 48461 (Sept. 16, 1993). PHMSA understands that other industry resources and Federal regulatory authorities contemplate the use of even lower LEL-based limits to manage ignition risks. See, e.g., Gas Pipeline Technology Committee, ANSI Z380.1-2022, "Gas Pipeline Technology Committee Guide for Gas Transmission, Distribution, and Gathering Piping Systems" (Mar. 2022) (establishing a threshold of 20 percent LEL in confined spaces and small substructures as for "grade 2" natural gas leaks that are potential future ignition hazards); NIOSH, "Immediately Dangerous to Life or Health (IDLH) Values," https://www.cdc.gov/niosh/idlh/criteria.html (last accessed Oct. 19, 2023) (basing IDLHs for flammable or combustible chemicals based on a threshold of 10 percent of LEL).

concurrent with the alarm location, for the personnel safety issues mentioned above) or a SCADA center, as the operator deems is most appropriate for their system. Complying with the requirements at the proposed §§ 195.263 and 195.452(i)(5) would not necessitate an operator to install a SCADA system if not already included as a part of their pipeline system, though an operator may choose to do so at their own discretion. Proposed requirements for the operations and maintenance of these fixed vapor detection and alarm systems are proposed at a new § 195.429; see section III.D.2 of this NPRM for further details on that proposal.

PHMSA expects the proposed requirements at §§ 195.263 and 195.452(i)(5) for fixed vapor detection and alarm systems would be reasonable, technically feasible, cost-effective, and practicable for operators of affected HVL (including carbon dioxide) pipelines. As noted above, fixed vapor detection and alarm systems are frequently used in industrial settings, including within the oil and gas industry, to protect facility personnel and provide defense-in-depth for timely identification of releases of a variety of gas-phase (or volatile) constituents that could be deleterious in that they are harmful (e.g., toxic, flammable/combustible, or asphyxiating) to human health or the environment. Some operators may already have such systems on their facilities as a strategy for complying with any of PHMSA operations, maintenance, and emergency manual requirements (e.g., § 195.402(c)(11)), leak detection (i.e., § 195.444), or IM program (i.e., § 195.452(i)(3)) requirements; OSHA process hazard analysis requirements (i.e., 29 CFR 1910.119(e)); or miscellaneous State requirements. Similarly, PHMSA has observed that several recent carbon dioxide pipeline greenfield projects have voluntarily committed to adopting "CO_2 monitoring devices" throughout their facilities[155]—demonstrating that fixed vapor detection systems are the sort of measure that reasonably prudent operators of carbon dioxide and other HVL pipelines would undertake in ordinary course given the potential lost commercial value and hazards to public safety and the environment from releases from their pipeline projects. Additionally, affected operators would be well-positioned to understand which constituents in the product streams they transport merit monitoring as deleterious to public safety or the environment; those operators would (within the parameters specified at § 195.263) also have the flexibility to select from a number of off-the-shelf fixed vapor detection alarm systems appropriate for the product streams transported in their facilities. Should an operator of any pipeline subject to §§ 195.263 or 195.452(i)(5) identify a compelling need for regulatory flexibility from this proposed requirement, the PSR provides for special permit procedures at § 190.341 to request a deviation.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed new requirements for fixed vapor detection and alarm systems 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 believes that its proposed compliance timeline (based on an effective date of the proposed requirements one year after the publication date of a final rule, which would necessarily be in addition to the time since issuance of this NPRM) would provide affected operators (specifically, for § 195.263, only HVL

[155] See, e.g., Navigator, S.D. Pub. Util. Comm. Doc. No. HP22-002, "Application for Permit to Construct the Navigator Heartland Greenway Project in South Dakota" at Exhibit D (Sept. 27, 2022); Wolf Carbon Solutions, IL Commerce Comm. Doc. No. 23-0475, "Direct Testimony of Patrick Brierley for the Mt. Simon Project" at Exhibit 3.2 (June 16, 2023).

pipelines that are newly constructed, replaced, relocated, otherwise changed, or converted to part 195 service; and for § 195.452(i)(5), only HVL pipelines that could affect an HCA) ample time to manage any related compliance costs and implementation challenges for their pipelines.

6. Removal of Carbon Dioxide as a Pressure Test Medium—§ 195.306

Section 195.306 prescribes the acceptable test mediums for pressure tests performed under subpart E of part 195. Paragraph (a) requires all pressure tests to use water as the test medium, unless excepted as provided under paragraphs (b), (c), or (d). Paragraph (c) and its subparagraphs provide alternatives to water as the test medium for pressure testing carbon dioxide pipelines under specific circumstances. Specifically, paragraph (c) allows for the use of inert gas or carbon dioxide as the test medium for pressure tests performed on carbon dioxide pipelines if the test meets five criteria: (1) the entire test section is outside of cities and other populated areas; (2) each building within 300 feet of the test section is unoccupied while the test pressure is equal to or greater than a pressure that produces a hoop stress of 50 percent of SMYS; (3) the maximum hoop stress during the test does not exceed 80 percent of SMYS; (4) continuous communication is maintained along entire test section; and (5) the pipe being tested is new pipe with a longitudinal joint factor of 1.00.[156]

Pressure tests can be used for a variety of purposes, including establishing MOP and detecting certain anomalies. In a traditional pressure test, the pipeline is filled with a fluid (often

[156] The longitudinal joint factor is a design factor used to compensate for the characteristic strength of a weld seam in a pipe. A pipeline joint with a longitudinal joint factor of 1.00 means that the pipeline joint is manufactured using modern manufacturing techniques and materials and is expected to not be susceptible to material or manufacturing defects. Certain older vintages of pipe made with historical practices or materials often have a longitudinal joint factor of less than 1.00, which essentially reduces the maximum pressure at which it can operate.

water or the transported product), which is then raised to a prescribed pressure and held for an extended duration; loss of pressure during this period may indicate leaks or fracture of the pipeline. Water is an excellent test medium for pressure testing for a number of reasons, including ease of access to the test medium and relative ease when determining the precise location of any test failures through the visible presence of water. In addition, the consequences of a failure during a pressure test using water as a test medium are significantly less than when using the transported product, due to reduced environmental impact and the absence of the threats of flammability, asphyxiation, and intoxication that may be presented by the product stream.

PHMSA recognizes that water remaining in the pipeline after a hydrostatic pressure test can result in higher-than-normal levels of internal corrosion due to the reaction of water with the carbon dioxide and the formation of hydrates.[157] PHMSA urges operators to adequately dewater until dry any pipeline that is intended to transport carbon dioxide and is pressure tested using water to prevent the acceleration of internal corrosion.[158] Monitoring the water content in the pipeline in accordance with PHMSA's proposals at § 195.579 (discussed in section III.G.2) and having adequate procedures for commissioning and re-start activities will help operators ensure that no free water can drop out at any location along the pipeline.

Due to the potentially corrosive interaction between carbon dioxide and free water, and to provide more flexibility for operators, PHMSA regulations also allow for the use of inert gas,

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[157] Barker et al, "Internal Corrosion of Carbon Steel Pipelines for Dense Phase CO_2 Transport in Carbon Capture and Storage (CCS) - A review", (2016).

[158] DNV-RP-F104: Dewater: removal of water content to ensure that no free water can drop out at any location along the pipeline during all potential scenarios during operation

such as nitrogen, as the pressure test medium, if the requirements of § 195.306(c)(1) through (5) are met. Use of an inert gas to perform a pressure test on a carbon dioxide product instead of water results in many of the same benefits; in particular, leaks or ruptures on a pipeline when pressure tested with inert gas have a reduced environmental impact, and the released test medium, by definition, is not flammable or reactive, greatly reducing the threat to individuals in the area. However, unlike with water as the test medium, pinpointing failure points on test sections when using an inert gas as the test medium is more difficult without a visual indication of where the failure occurred, especially when the failure mechanism is a leak. Thus, additional measures, such as maintaining communications along the test segment, not performing such tests in populated areas, and ensuring nearby buildings are unoccupied during higher pressure portions of the test, are prudent when using inert gas as a test medium.

When considering a highly volatile product like carbon dioxide, however, the environmental and human health consequences could be severe in the event of a pressure test failure. Notably, paragraph (b) of § 195.306 specifically excludes HVLs as a possible test medium on hazardous liquid pipelines; however, paragraph (c) allows for the use of carbon dioxide as a test medium on carbon dioxide pipelines under specific circumstances. Paragraph (c)(2) of § 195.306 only requires that buildings within 300 feet of the test section be unoccupied during higher pressure portions of the test; as seen in the 2020 accident in Satartia, carbon dioxide vapor clouds can migrate distances far in excess of 300 feet. Asphyxiating concentrations of carbon dioxide were observed in that accident up to one mile (5,280 feet) from the failure location. In addition, the requirements of § 195.306(c) do not account for individuals passing through the area, including a lack of requirements to restrict access to roads or other routes of transportation in the area surrounding the test segment. Individuals in automobiles or other modes of transportation are just as susceptible to asphyxiation from carbon dioxide vapor clouds as those within buildings, as shown by the 2020 accident in Satartia, where multiple individuals lost consciousness within a vehicle that stalled inside the carbon dioxide vapor cloud. With the reasonable and safer alternatives of water and inert gas as test mediums for use by carbon dioxide pipeline operators, PHMSA finds that the use of carbon dioxide as a test medium represents an unnecessary and unmanageable risk to the public and the environment.

Therefore, PHMSA proposes to remove carbon dioxide as an acceptable test medium for pressure tests on carbon dioxide pipelines. The ability for operators of carbon dioxide pipelines to use inert gas when pressure testing carbon dioxide pipelines, should they meet the requirements of § 195.306(c)(1) through (5), would remain unchanged. PHMSA does not consider carbon dioxide to be an inert gas, and under this proposal, carbon dioxide would be specifically excluded from the acceptable test mediums on carbon dioxide pipelines. The ability of carbon dioxide pipeline operators to use water as the test medium under § 195.306 would remain unchanged.

PHMSA understands that the proposed change to the permissible test mediums for pressure tests on carbon dioxide pipelines discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected pipeline operators. Carbon dioxide pipeline operators—should test sections meet the requirements of § 195.306(c)(1) through (5)—would still be granted the alternative test medium of inert gas, in addition to the test medium of water permitted for all part 195-regulated pipelines. Further, given the potential consequences to the public and the environment of a failure during a pressure test conducted using carbon dioxide as the test medium, use of water or inert gas would better protect the public, the environment, and operators' pipelines from loss of commercially valuable commodities. Also, should an operator identify a compelling need for regulatory flexibility, the PSR provides for special permit procedures at § 190.341 to request a deviation from this new regulatory prohibition.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed amendment 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 believes that operator compliance timelines (one year after the publication date, which would necessarily be in addition to the time since issuance of this NPRM) would provide operators ample time to implement requisite changes in their testing protocols and manage any related compliance costs and implementation challenges.

7. Addition of Hydrostatic Spike Pressure Testing Section—§§ 195.309 and 195.588

Spike hydrostatic pressure tests (spike tests) are a specialized subset of pressure tests and are a useful tool to detect cracks or crack-like defects. In a spike hydrostatic pressure test, the test medium (water) within the pipe is pressurized to a baseline pressure, which is usually the pressure required to establish the MOP. Once the pressure is stabilized within the first portion of the baseline pressure test, the pressure is then raised for a short time period to the spike pressure, after which the pressure is lowered to the baseline test pressure for the remainder of the test, which is longer in duration than the spike portion of the test.

Part 195 contains one reference to spike hydrostatic pressure testing, located at § 195.588. This section specifies the requirements for direct assessment on both carbon dioxide and hazardous liquid pipelines. Section 195.588(c)(4)(ii) requires that, when operators opt to complete a spike hydrostatic pressure test when performing the remediation required by § 195.588(c)(4), that test must meet the following requirements: (1) the test medium is water,

(2) the minimum test pressure for the spike test is between 100 and 110 percent of SMYS, (3) the duration of the spike test is 30 minutes, (4) the spike test is immediately followed by a subpart E pressure test, and (5) the subpart E pressure test is continuously maintained for at least 8 hours.

Most pressure test requirements for part 195 pipelines are located within subpart E. These requirements include the pipelines for which pressure testing is required, required test pressures, and acceptable testing mediums. Section 195.304 requires pressure tests that operators conduct in accordance with subpart E have the pressure held for at least 4 continuous hours at 125 percent of MOP or greater if visually inspected, and if not visually inspected, have the pressure held, at a minimum, for an additional 4 continuous hours at 110 percent of MOP or greater. Thus, the 8-hour test duration is only required if the operator does not choose to visually inspect the pipeline during the test; many operators choose to visually inspect the pipeline during hydrostatic testing.

Section 195.306 requires that pressure tests conducted under subpart E use water as the test medium, with some exceptions. Under existing regulations, operators are permitted to use carbon dioxide or an inert gas as the test medium for carbon dioxide pipelines if several conditions are met; the same is true of using liquid petroleum as a test medium for hazardous liquid pipelines. Operators may use air or inert gas for low-stress pipelines. Many operators choose allowable test mediums other than water. For further information on test mediums for carbon dioxide, see section III.C.6, which discusses proposed changes at § 195.306 pertaining to acceptable test mediums for carbon dioxide pipelines.

With the proposed modifications at § 195.5, "Conversion to service subject to this part,"[159] the PSR would contain an additional section that would require spike hydrostatic pressure testing in addition to the requirements at § 195.588 for pipelines that are converted to carbon dioxide service. As discussed in section III.E of this NPRM, PHMSA is proposing that operators converting pipeline segments to transport carbon dioxide perform this additional test to ensure a higher margin of safety, considering the mounting interest in rapid development and operation of CCUS infrastructure, including the repurposing and conversion of existing pipelines. As the current language at § 195.588 conflicts with §§ 195.304 and 195.306 regarding the required test duration, test pressure, and test medium, this can be confusing for operators. For these reasons, PHMSA is proposing the addition of a new § 195.309 to clearly define the requirements of a spike hydrostatic pressure test within subpart E. PHMSA is also proposing conforming changes at §§ 195.5 and 195.588 to reference the newly proposed § 195.309 instead of listing the requirements of the spike hydrostatic pressure test in those sections. PHMSA also proposes a typographical correction at § 195.588(c)(4)(i) to correct a paragraph reference that should point to paragraph (c)(4)(ii) of § 195.588 instead of paragraph (b)(4)(ii). In addition, PHMSA proposes a change to the title of § 195.588 to refer to the section content without doing so in the form of a question. In the final rule that created subpart H under part 195, including § 195.579, RSPA stated "In accordance with Federal Register guidelines, we drafted final subpart H in an easier to read and understand format. Section headings are in the form of questions. We minimized passive voice and used the word "you" as a substitute for

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[159] See Section III.E of this NPRM.

"operator.""'[160] This approach to drafting regulatory text is no longer in accordance with Federal Register guidelines[161] or favored by PHMSA and does not match the regulatory text that has been added or amended in part 195 since the creation of subpart H.

PHMSA proposes the requirements for a spike hydrostatic pressure test in § 195.309 to be as follows: (1) water as the test medium; (2) a spike pressure of at least 150 percent of MOP or 100 percent of SMYS, whichever is less; (3) the spike pressure is reached within the first 2 hours of the pressure test; (4) the spike pressure is held for at least 30 minutes; (5) the baseline pressure for the test is at least 125 percent of MOP; and (6) a total test duration of at least 8 continuous hours.

Use of water as a test medium for § 195.309 is a prudent safety measure when considering that spike hydrostatic pressure tests would be used in circumstances where a failure during the test is more likely than a typical subpart E pressure test; namely, in response to suspected stress corrosion cracking or as part of a conversion to service project. A spike test used as an integrity assessment on pipe with known or suspected cracks or crack-like defects (such as stress corrosion cracking) or on pipe with unknown or incomplete operating and maintenance history (as is often the case with pipelines converted to service) presents a much higher likelihood of the pipeline segment experiencing a leak or rupture during the test, with the resultant consequences of that failure. Using water when performing a spike test, therefore, results in a lower risk to the public and the environment than using commodity product, whether

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[160] 66 FR 67002 (*https://www.govinfo.gov/content/pkg/FR-2001-12-27/pdf/01-31655.pdf*).
[161] National Archives and Records Administration - Office of the Federal Register, "Document Drafting Handbook", Revision 3, (June 21, 2017).

that product is hazardous liquid or carbon dioxide. PHMSA recognizes that water remaining in the pipeline after a hydrostatic pressure test can result in higher-than-normal levels of internal corrosion due to the reaction of water with the carbon dioxide and the formation of hydrates.[162] PHMSA urges operators to adequately dewater until dry any pipeline that is intended to transport carbon dioxide and is pressure tested using water to prevent the acceleration of internal corrosion.[163] Monitoring the water content in the pipeline in accordance with PHMSA's proposals at § 195.579 (see section III.G.2) and having adequate procedures for commissioning and re-start activities will help operators ensure that no free water can drop out at any location along the pipeline.

The minimum spike test pressure proposed is consistent with previous rulemakings,[164] technical reports,[165] and PHMSA-sponsored research.[166] Preexisting language at § 195.588(c)(4)(ii) requires a spike pressure of between 100 and 110 percent of SMYS; however, as noted in operator comments[167] to PHMSA on previous NPRMs, maintaining pressures above 100 percent of SMYS may deform the pipe. Accordingly, PHMSA is proposing to require a spike pressure of the lesser of 150 percent of MOP or 100 percent SMYS. This represents a

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[162] Barker et al, "Internal Corrosion of Carbon Steel Pipelines for Dense Phase CO_2 Transport in Carbon Capture and Storage (CCS) - A review", (2016).
[163] DNV-RP-F104: "Dewater: removal of water content to ensure that no free water can drop out at any location along the pipeline during all potential scenarios during operation." "The pipeline should be dried to a dew point of -40°C to -45°C (at ambient pressure) before filling with CO_2."
[164] 84 FR 52180, "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments," (October 1, 2019).
[165] ASME, STP-PT-011, "Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas," (2008).
[166] Battelle Memorial Institute, "Final Summary Report and Recommendations for the Comprehensive Study to Understand Longitudinal ERW Seam Failures—Phase II," (August 2017). https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=390
[167] https://www.regulations.gov/comment/PHMSA-2011-0023-0353

lower spike pressure than the current requirements at § 195.588(c)(4)(ii); however, as noted above, PHMSA-sponsored research supports that this spike pressure is sufficient to detect crack-type anomalies.

The minimum baseline pressure of 125 percent of MOP proposed is consistent with the existing baseline pressure required at § 195.304. The minimum duration proposed for which the spike pressure is held (30 minutes) and the proposed minimum total test duration (8 hours) are both consistent with the existing language at § 195.588(c)(4)(ii). These proposed baseline test pressure and test durations have been in place at § 195.588(c)(4)(ii) since 2017 and have a proven safety record.

Lastly, requiring operators to reach the spike pressure within the first 2 hours of the pressure test reflects real-world conditions when performing a pressure test while still ensuring pipeline safety. Raising the pressure from the baseline pressure to the spike pressure is not an instantaneous process that can be accomplished immediately. On the other hand, performing the spike test at the end of a pressure test does not provide sufficient time to detect failure conditions and may mask defects and anomalies exposed by the higher spike pressure. Cracks and crack-like defects, in some cases, may be susceptible to a phenomenon called "pressure reversal," which is the failure of a defect at a pressure less than a pressure level that the flaw has previously experienced and survived. The increased stress from the test pressure may cause latent cracks, which are not quite large enough to fail, to grow during the test. If the crack does not fail before the test is completed, the resultant crack that remains in the pipe may be large enough to no longer be capable of passing another pressure test. The spike portion of the pressure test is designed to cause such marginal crack defects to fail during the early, spike phase of the pressure test. The post-spike, long-duration test pressure validates the operational strength of the pipe.

Allowing time for the operator to reach the spike pressure (a maximum of 2 hours) and following that spike pressure test with a longer baseline pressure test duration (a minimum of 5.5 hours following the completion of the spike test) strikes an appropriate balance between ensuring robust safety while still allowing for the realities of implementation.

PHMSA understands that the proposed relocation of, and clarifying changes to, hydrostatic spike pressure testing requirements discussed above would be reasonable, technically feasible, cost-effective, and practicable for affected pipeline operators. As discussed above, most of those requirements merely relocate pre-existing requirements into a new, dedicated provision governing all part 195 hydrostatic spike testing. To the extent that certain new requirements (e.g., the requirement to perform a 2-hour spike test at the beginning of a pressure test) may diverge from existing operator pressure testing protocols, PHMSA understands those protocols could be adjusted accordingly without significant difficulty. Should an operator of a hazardous liquid or carbon dioxide pipeline identify a compelling need for regulatory flexibility from the requirements within the new § 195.309, the PSR provides for special permit procedures at § 190.341 to request a deviation.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed new § 195.309 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 believes that operator compliance timelines based on an effective date of the proposed requirements one year after the publication date of a final rule—which would necessarily be in addition to the time since issuance of this NPRM—would provide affected operators ample time to implement requisite changes in their pressure testing practices and manage any related compliance costs.

8. Conforming Changes—§§ 195.3, 195.8, 195.18, 195.120, 195.260, 195.262, and 195.302

Conforming changes in subparts C, D, and E are proposed at §§ 195.3, 195.8, 195.120, 195.260, 195.262, and 195.302. These conforming changes fall into three general categories: (1) incorporations by reference in response to other proposals; (2) changes to accommodate the proposed definition change for carbon dioxide; and (3) changes to accommodate the proposed definition update for HVL.

Section 195.3[168] lists which documents are incorporated by reference within part 195. This NPRM proposes to modify § 195.3(b)(13) to incorporate API Specification 5L into § 195.111.

API Specification 5L, "Specification for Line Pipe," which is already incorporated by reference into part 195, approved for § 195.106(b) and (e), prescribes the minimum requirements for the manufacture of new seamless and welded steel line pipe. PHMSA proposes to incorporate this standard by reference into the requirements at §195.111, "Fracture propagation." Within API Specification 5L, requirements for toughness testing are specified, including Charpy v-notch testing and drop weight tear testing, both of which are required for certain carbon dioxide

[168] In parallel rulemakings (RINs 2137-AF13 and 2137-AF48) PHMSA has proposed updating API Specification 5L as well as several other consensus industry standards incorporated by reference throughout part 195, including sections of that part that may be applicable to carbon dioxide and hazardous liquid pipelines that would be affected by the proposals in this NPRM. See PHMSA, "Proposed Rulemaking: Periodic Updates of Regulatory References to Technical Standards and Miscellaneous Amendments," 86 FR 3938 (Jan. 15, 2021); PHMSA, "Proposed Rulemaking: Periodic Standards Update II" 87 FR 52713 (Aug. 29, 2022). Should PHMSA issue final rules in those parallel rulemakings incorporating updates to those consensus industry standards within the PSR, it will note in those final rules (as well as in a final rule on this NPRM) that incorporation of those updated standards would have constructively modified the proposals in this NPRM.

pipelines at § 195.111. Thus, this standard is an appropriate reference for incorporation in § 195.111.

Section 195.8 allows for the transportation of hazardous liquids and supercritical-phase carbon dioxide in non-steel pipelines when notification is provided to the PHMSA Administrator. PHMSA is proposing a conforming change to the effective dates in this section to allow for the transportation of gas- and liquid-phase carbon dioxide in non-steel pipelines, consistent with the new definition change for carbon dioxide at § 195.2. Specifically, PHMSA proposes to add a compliance date simultaneous with the effective date (which effective date itself would itself be one year after the publication date of a final rule) for carbon dioxide transported in the gas or liquid phases (in concentrations greater than 50 percent) or in the supercritical phase (in concentrations greater than 50 percent and less than or equal to 90 percent). PHMSA proposes that the operator notification to PHMSA include the phase of carbon dioxide to be transported, if applicable. In addition, PHMSA proposes to replace a pronoun referring to the PHMSA Administrator in this section with the agency name. PHMSA requests comment on the appropriateness of allowing carbon dioxide transportation by non-steel pipelines with operator notification to PHMSA.

Section 195.18 provides the requirements for notifications to PHMSA required by part 195. In this rulemaking, PHMSA proposes to add § 195.5 to the list of sections for which § 195.18(c) is applicable.[169] PHMSA also proposes changing "letter" to "response," "the Associate Administrator of Pipeline Safety" to "PHMSA," and "additional time and/or

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[169] See section III.E for more details on this cross-reference.

information" to "additional time or additional information" to allow more timely responses to operators providing such notifications to PHMSA.

Section 195.120 details when a pipeline must be designed to accommodate internal inspection devices, also known as in-line inspection (ILI) tools. Paragraph (b) lists exceptions to this requirement, including station piping. This NPRM proposes a conforming change at §195.120(b)(2) by adding compressor stations to the list of excepted station piping, consistent with the addition of the gas phase to the definition of carbon dioxide at § 195.2. PHMSA also proposes a clarifying change at § 195.120(b)(4) to provide examples of crossovers, such as at mainline valves and between parallel pipelines.

Section 195.260 specifies the locations where operators are required to install valves, including the maximum spacing between valves. Among other locations, valves are required at the suction and discharge ends of pump stations to allow for the isolation of those stations from other facilities. With the addition of the gas phase to the definition of carbon dioxide, and because carbon dioxide is an asphyxiant, it is prudent that operators install valves at equivalent locations at compressor stations (compared to pump stations) for operations and maintenance purposes, as well as for isolation purposes in the event of an emergency. Thus, PHMSA is proposing conforming changes at § 195.260(a) to reflect the addition of compressor stations to facilities regulated under part 195 with the addition of gas-phase carbon dioxide.

PHMSA is also proposing clarifying language regarding valve spacing requirements on pipelines transporting HVLs. As this NPRM proposes to clarify carbon dioxide's status as an HVL through a change in the definition of an HVL, conforming changes are required at other paragraphs of § 195.260 to provide clarity to operators on relevant valve spacing requirements. Paragraph (g) of § 195.260 establishes the maximum valve spacing for pipelines transporting

HVLs in highly populated areas or other populated areas; this NPRM proposes to add a clarifying statement that notes that pipelines transporting carbon dioxide are included within the definition of pipelines transporting HVLs.

Section 195.262 outlines the basic safety equipment required at pump stations, including adequate ventilation, emergency shutdown capabilities, overpressure safety devices, and fire protection equipment. With the addition of the gas phase to the definition of carbon dioxide and because carbon dioxide is an asphyxiant, it is prudent that operators include appropriate safety equipment at compressor stations as well to protect operator employees. Thus, PHMSA is proposing conforming changes at § 195.262 to require the availability of critical safety equipment at compressor stations. PHMSA is also proposing a change to the title of § 195.262 to reflect the expanded scope of the section.

Section 195.302 states that pipelines operating under part 195 must have a subpart E pressure test completed prior to service and provides compliance dates for those pressure tests. Paragraph (b)(2) states that, except for pipelines converted under § 195.5, pipelines transporting carbon dioxide that were constructed prior to July 12, 1991, may be operated without pressure testing under subpart E if the pipeline (1) has an MOP determined in accordance with § 195.406(a)(5) or (2) is located in a rural area as part of a production field distribution system.

Due to the proposed change in the definition of carbon dioxide, additional existing pipelines may become newly regulated under part 195 without converting to part 195 service pursuant to § 195.5. These newly regulated pipelines may not have had pressure testing completed under subpart E as required by § 195.302(a). Pipelines transporting supercritical-phase carbon dioxide consisting of greater than 50 percent and less than or equal to 90 percent carbon dioxide molecules, and which were constructed prior to the effective date of a final rule in this proceeding, would be excepted from certain part 195 subpart E pressure testing requirements at § 195.302(a). In addition, pipelines transporting gas- or liquid-phase carbon dioxide consisting of greater than 50 percent carbon dioxide molecules, and which were constructed prior to the effective date of a final rule in this proceeding would be similarly excepted from certain subpart E pressure testing requirements. This NPRM proposes to reflect these newly excepted carbon dioxide pipelines by restructuring § 195.302(b)(2) into three subparagraphs: (i) pipelines transporting carbon dioxide meeting the existing definition; (ii) pipelines transporting supercritical-phase carbon dioxide meeting the proposed definition; and (iii) pipelines transporting gas- or liquid-phase carbon dioxide meeting the proposed definition.

Implementing this proposed change would require operators of these existing carbon dioxide pipelines that would be excepted from certain subpart E pressure testing requirements to establish MOP under § 195.406(a)(5). The MOP for carbon dioxide pipelines meeting the requirements of § 195.302(b)(2)(ii) and proposed (b)(2)(iii) would be 80 percent of the test pressure or highest operating pressure to which the pipeline was subjected for 4 or more continuous hours, which can be demonstrated by recording charts or logs made at the time the test or operations were conducted.

PHMSA has experience applying similar exceptions from certain subpart E pressure testing requirements to other part 195 historical pipelines, including interstate pipelines transporting hazardous liquids constructed before January 8, 1971, and low-stress pipelines transporting HVLs constructed before August 11, 1994. PHMSA has also used this approach for excepted supercritical-phase carbon dioxide pipelines in the past.[170] Similarly, PHMSA proposes using this approach to determine the MOP of newly excepted pipelines transporting carbon dioxide meeting the proposed definition of this NPRM at § 195.2, namely, gas- and liquid-phase carbon dioxide, and supercritical-phase carbon dioxide in concentrations greater than 50 percent and less than or equal to 90 percent of the total product stream. This approach allows operators of these existing pipelines to operate under part 195 while allowing for a margin of conservatism for safety.

As part of these proposed changes, PHMSA proposes to reorganize the structure of paragraph (b)(2) of § 195.302 to mirror the structure of paragraph (b)(1), which contains the list of excepted pipelines transporting hazardous liquids. This NPRM proposes to move the statement that these newly excepted pipelines have an MOP defined by § 195.405(a)(5) into the introductory text of paragraph (b)(2), consistent with the structure of (b)(1). This proposal would make the original (b)(2)(ii), the exception for carbon dioxide pipelines in a rural area as part of a production field distribution system, no longer applicable under the proposed changes to (b)(2), as PHMSA does not require those pipelines to have MOP defined by § 195.405(a)(5). As such, PHMSA is proposing to move this exception to a new paragraph §195.302(b)(5). This proposal would not change the pressure test exception for those pipelines or the requirements regarding their MOP determination.

D. Updated Operations and Maintenance Procedures—§ 195.401, 195.404, 195.406,

[170] See RSPA, "Final Rule: Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines", 59 FR 29379 (June 7, 1994).

195.412, 195.429, 195.434, 195.436, and 195.438

1. Enhanced Requirements on Identifying and Addressing Geologic Hazards and the Threat of Reduced Depth of Cover—§ 195.412

Section 195.412 requires operators of hazardous liquid and carbon dioxide pipelines to perform recurring inspections of the pipeline right-of-way and navigable water crossings.[171] At least 26 times each calendar year (in intervals not exceeding 3 weeks), an operator must inspect the surface conditions on or adjacent to the right-of-way, per § 195.412(a). These inspections can be performed by walking, driving, or flying the right-of-way, or by using other methods as appropriate. Paragraph (b) requires operators of onshore hazardous liquid pipelines that cross under navigable bodies of water to inspect each crossing (which inspection may involve sonar or other under water inspection technologies) at least once every 5 years to determine the condition of the crossing.

Right-of-way inspections, if done properly by qualified personnel and at regularly occurring intervals, can alert operators to conditions affecting the safety and operation of the pipeline. The purpose of these patrols is to identify conditions that may pose a threat to the pipeline, such as construction and excavation; areas of dead vegetation and other potential indicators of leaks; damaged or missing pipeline markers; exposed pipelines or areas of reduced depth of cover; unauthorized right-of-way activities; and erosion, earth movement, and other

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[171] "Navigable waters" means those waters of the United States, including the territorial seas adjacent thereto, the general character of which is navigable, and which, either by themselves or by uniting with other waters, form a continuous waterway on which boats or vessels may navigate or travel between two or more States, or to or from foreign nations. See Interpretation Response #PI-73-037 for further details. https://www.phmsa.dot.gov/regulations/title49/interp/PI-73-037

geologic hazards. PHMSA advisory bulletins ADB-2019-02[172] and ADB-2022-01[173] note that "[r]ight-of-way patrol staff must be trained on how to detect and report to appropriate staff the conditions that may lead to or exhibit ground movement."

Numerous standards discuss industry best practices on right-of-way inspections, including what conditions can be identified by these patrols. ASME B31.8S[174] notes that "when a pipeline is patrolled, evidence of third-party encroachment may be discovered." API RP 1175[175] notes that surveillance patrols are part of the "minimum regulatory means to detect leaks," alongside other requirements. API RP 1133[176] states that personnel performing right-of-way inspections "should be trained to identify areas that are potentially susceptible to washout, scour, erosion, subsidence, or other conditions that could be detrimental to the safe operation of the pipeline." API RP 1160[177] states that "operators should attempt to prevent or mitigate the damage from…geophysical events such as landslides, land erosion, or subsidence that could cause releases;" recommended actions include "training patrol pilots to spot areas of developing soil instability, landslides, and subsidence" and "conducting patrols as soon as feasible after the passage of severe weather or flooding."

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[172] PHMSA, 84 FR 18919, ADB-2019-02, "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards," (May 2, 2019).
[173] PHMSA, 87 FR 33576, ADB-2022-01, "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards," (June 2, 2022).
[174] ANSI/ASME B31.8S, "Managing System Integrity of Gas Pipelines, Supplement to B31.8," 2004 edition (January 1, 2005).
[175] API RP 1175, "Pipeline Leak Detection—Program Management," 1st edition, (December 2015).
[176] API RP 1133, "Guidelines for Onshore Hydrocarbon Pipelines Affecting High Consequence Floodplains," 1st edition, (February 2005).
[177] API RP 1160, "Managing System Integrity for Hazardous Liquid Pipelines," 3rd edition, February 2019.

When performing right-of-way inspections, it is prudent for operators to inspect the surface conditions of both the right-of-way itself and areas adjacent to the right-of-way. Some threats outside of the right-of-way may affect the safety and operation of the pipeline, and operator inspections of these adjacent areas can prevent accidents. For example, an operator who observes construction activity adjacent to a right-of-way may take action to prevent third-party damage to their pipeline system by contacting the excavation or construction company proactively to inform them of their proximity to the pipeline; ensure pipeline markers are in place and contain up-to-date information; confirm depth of cover is adequate and consistent with original pipeline burial depth; or take other preventative actions, as appropriate. Likewise, inspections adjacent to the right-of-way can alert operators to geologic hazards that may affect their pipeline systems.

Geologic Hazards

One of the primary reasons for the inspection requirement at § 195.412(a) is to monitor for geological movement, whether slowly occurring or acute in origin, which may affect the current or future safe operation of the pipeline. Geologic hazards (also known as geological hazards, geophysical hazards, geo-technical hazards, or geohazards) are geological processes and/or phenomenon that occur when geologic conditions have the potential to damage a pipeline or right-of-way or impact the safe operation of a pipeline. Geologic hazards include earthquakes, landslides, sinkholes, erosion, and ground subsidence, among others. Geologic hazards also include soil movement caused by man-made events (i.e., construction activities that cause soil instability and ground movement on a nearby slope). These hazards are independent of the product transported, whether it be hazardous liquid or carbon dioxide, and have been observed in all 50 States and territories.[178]

Potential warning signs of an impending landslide movement, a type of geologic hazard, may include collapsed pavement or cracking of paved areas, bulging ground at the base of a slope, or leaning or tilted trees.[179] These warning signs may not be visible on a right-of-way but could be readily apparent in the adjacent area; landslides and other geologic hazards are capable of moving large volumes of earth significant distances from their originating location.[180] Regular inspections of pipeline rights-of-way and adjacent areas over time can also alert operators to worsening conditions that may indicate a geologic hazard presents an impending risk to the pipeline.

Numerous recent failures across the United States on hazardous liquid and carbon dioxide pipelines have resulted from the lack of identification and/or timely remediation of geologic hazards. As noted in section II.D, the cause of the 2020 Satartia accident was axial strain on the pipeline from a landslide, which originated at a roadside embankment. The Federal Emergency Management Administration noted in a 2017 factsheet[181] that roadside embankments are particularly susceptible to landslides. Some of the other more notable recent accidents on part

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[178] https://www.usgs.gov/programs/landslide-hazards/landslides-101

[179] FEMA, "Fact Sheet: Recognize Landslide Warning Signs," (October 17, 2017). https://www.fema.gov/press-release/20210318/fact-sheet-recognize-landslide-warning-signs.

[180] On May 25, 2014, a landslide which extended approximately 2.8 miles long displaced approximately 38 million cubic yards of rock, vegetation, and topsoil. https://coloradogeologicalsurvey.org/publications/west-salt-creek-landslide-catastrophic-rockslide-avalanche-mesa-colorado/

[181] FEMA, "Fact Sheet: Recognize Landslide Warning Signs," (October 17, 2017), https://www.fema.gov/press-release/20210318/fact-sheet-recognize-landslide-warning-signs.

195 pipelines caused by geologic hazards, including those discussed in the 2022 advisory bulletin ADB-2022-01,[182] are briefly described below:

1. On March 11, 2022, a 22-inch pipeline spilled 3,900 barrels of crude oil adjacent to Cahokia Creek, approximately 15 miles east of St. Louis, Missouri. Preliminary information indicates land movement may have contributed to this failure. The NTSB accident investigation continues as of the date of this NPRM.[183]
2. On May 30, 2021, a pipeline spilled 640 barrels of gasoline in Greens Bayou, affecting HCAs near Houston, Texas. The operator's self-reported cause indicated earth movement over time on the bank of a bayou.
3. On April 30, 2018, an 8-inch pipeline failed in a remote mountainous region of Marshall County, West Virginia, resulting in the release of 2,658 barrels of propane. The failure was caused by lateral movement of the pipeline due to earth movement along the right-of-way.
4. On December 5, 2016, approximately 14,400 barrels of crude oil were spilled into an unnamed tributary to Ash Coulee Creek, Ash Coulee Creek itself, the Little Missouri River, and their adjoining shorelines in Billings County, North Dakota. The metallurgical and root cause failure analysis indicated the failure was caused by compressive and bending forces due to a landslide impacting the pipeline. The landslide was the result of excessive moisture within the hillside, which created unstable soil conditions.

[182] 87 FR 33576, ADB-2022-01, "Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by Earth Movement and Other Geological Hazards," (June 2, 2022),
[183] https://www.ntsb.gov/investigations/Pages/PLD22FR002.aspx

5. On October 21, 2016, a pipeline release of more than 1,238 barrels of gasoline spilled into the Loyalsock Creek in Lycoming County, Pennsylvania. The release was caused by extreme localized flooding and soil erosion.

Other Federal agencies have also found geologic hazards may cause significant damage to pipelines. According to one study conducted for the U.S. Geological Survey (USGS) and the California Geological Survey,[184] numerous oil and gas pipeline failures have occurred due to ground shaking. The authors note that "[b]uried pipelines are vulnerable to permanent ground deformation and wave propagation (shaking). Ground deformation can include fault rupture, landslide, and liquefaction and associated lateral spreading and settlement." The study further notes that pipeline damage mechanisms can include "compression/wrinkling, joint weld cracking/separation (particularly for oxy-acetylene welds), bending/shear resulting from localized wrinkling, and tension." In addition, the study notes that "landslides can load buried pipelines in a similar manner to fault rupture…In catastrophic landslide failures, the pipe may be left unsupported."

Numerous resources are available to operators for geologic hazard identification, prevention, mitigation, and remediation. The National Oceanic and Atmospheric Administration's National Centers for Environmental Information has excellent information publicly available. For example, see the National Temperature and Precipitation Maps at the National Centers for Environmental Information.[185] The USGS also has excellent information

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[184] Porter, K., Jones, L., Cox, D., Goltz, J., and Hudnut, K. (2011). "The ShakeOut scenario: A hypothetical Mw7. 8 earthquake on the southern San Andreas fault." Earthquake Spectra, 27(2), 239-261. Transportation of Hazardous Liquids by Pipeline, 49 CFR §195 (2011).

[185] https://www.ncdc.noaa.gov/temp-and-precip/us-maps/

publicly available regarding land movement.[186] In addition, the USGS notes in their publicly available material[187] that geologic investigations and good engineering practices can reduce landslide hazards, a common type of geologic hazard. PHMSA has also funded research and development projects on the impact of soil movement and pipeline monitoring, including: "Pipeline Integrity Management for Ground Movement Hazards,"[188] "Combined Vibration, Ground Movement, and Pipe Current Detector,"[189] "Definition of Geotechnical and Operational Load Effects on Pipeline Anomalies,"[190] and "Fiber Optic Sensors for Direct Pipeline Monitoring Under Geohazard Conditions."[191]

Industry standards also provide guidance on geologic hazards to operators. API RP 1160 notes that operators should consider "providing for movement of the pipeline to occur without damaging the pipeline at seismic fault crossings, unstable slopes, or areas of subsidence" and consider "routinely gathering updated [geographic information system (GIS)] data regarding fault zones, land use, etc." API RP 1160 further notes that "[s]eismic monitoring of known geologically unstable areas can assist in providing warning of earth movement" and "[s]train gauges can monitor the strains being applied to the pipeline as a result of gradual earth movement." Further, API RP 1160 notes that, after indications of a geologic hazard have occurred, an operator "should consider consulting a geotechnical or structural engineer to

[186] For example, see the Landslide Hazards Maps at the USGS website (https://www.usgs.gov/programs/landslide-hazards/maps).
[187] https://www.usgs.gov/programs/landslide-hazards/landslides-101
[188] https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=202
[189] https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=655
[190] https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=561
[191] https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=889

evaluate the pipeline if damage is apparent and the integrity of the pipeline is unknown." API RP 1133 notes that pipeline operators "should be alert to weather patterns and conditions that are precursors to flooding or soil movement and have personnel available for surveillance, preventative maintenance activities and emergency response actions." API RP 1188[192] notes possible methods available to operators for the identification of weather or other outside forces (which includes geologic hazards) include "[v]isual inspection, national weather and geological services, strain gauges, piezometers, line marker movement, survey, inclinometers, rain gauges, [light detection and ranging technology (LIDAR)], photogrammetry, seismograph, and other technologies."

Because geologic hazards occur on all pipelines, independent of the product transported, part 195-regulated operators can also use guidance available to part 192-regulated operators when identifying, preventing, mitigating, or remediating geologic hazards. ASME B31.8S[193] Appendix A9 contains information on developing IM programs to address the threat of weather and outside forces, including geologic hazards. ASME B31.8S notes that pipe may be susceptible to extreme loading at the following locations: where the pipeline crosses a fault line; where the pipeline traverses steep slopes; where the pipeline crosses water or is adjacent to water or where the river bottom is moving; where the pipeline is subject to extreme surface loads that cause settlement to underlying soils; where blasting near the pipeline is occurring; where the pipe is at

[192] API RP 1188, "Hazardous Liquid Pipeline Facilities Integrity Management," 1st edition, January 2022.
[193] ANSI/ASME B31.8S, "Managing System Integrity of Gas Pipelines, Supplement to B31.8," 2004 edition, (January 1, 2005).

or above the frost line; where the soil is subject to liquefaction; and where ground acceleration exceeds 0.2 g.

ASME B31.8S further notes that, for weather-related and outside force threats, integrity assessments—including inspections, examinations, and evaluations—are normally conducted per the requirements of operations and maintenance procedures, and "[a]dditional or more frequent inspections may be necessary, depending on leak and failure information."

ASME B31.8S also notes that mitigation activities may include: "stabilization of the soil, stabilization of the pipe or pipe joints, [and] relocation of the pipeline." ASME B31.8S further notes that for susceptible pipelines, "line patrolling should be used to perform surface assessments. In certain locations, such as known slide areas or areas of ongoing subsidence, the progress of the movement should be monitored."

Reduced Depth of Cover

In addition to geologic hazard identification, a proper inspection of the right-of-way can identify exposed pipelines or areas of reduced depth of cover from the original pipeline burial depth. The threat of reduced depth of cover (up to and including pipeline exposure) can occur in parallel with threats presented by geologic hazards, such as landslides exposing pipelines due to soil or pipe movement. This threat can also present in tandem with other threats, such as increased construction or agricultural activity, severe weather events such as flooding, and regular scour at water crossings, or as a separate threat altogether, unrelated to any other threats present on the pipeline system.

Numerous resources are available to pipeline operators on the use of depth of cover as an important preventative and mitigative measure for certain threats. ASME RP 1133, Guidelines for Onshore Hydrocarbon Pipelines Affecting High Consequence Floodplains,[194] notes that "depth should be maintained to eliminate impacts from the future migration" of water channels in crossings and that the depth of burial must be below the level of scour. ASME RP 1160, Managing System Integrity for Hazardous Liquid Pipelines,[195] includes "performing a depth of cover survey and proactively lowering shallow pipe in actively tilled land or areas where significant construction activity is occurring, planned or expected" as an option for the prevention or mitigation of the threat of mechanical damage. ASME RP 1160 states that data from right-of-way condition surveys and depth-of-burial surveys, among numerous other data types, "should be collected and integrated in support of an integrity management program" and if this "data is missing or incomplete, the operator should attempt to collect this data."

Like geologic hazards, the threat presented by reduced depth of cover (up to and including pipeline exposure) occurs independent of the transported product. This allows operators of part 195-regulated pipelines to use guidance available to part 192-regulated operators when identifying, preventing, mitigating, or remediating depth of cover issues. Table 4 of ASME B31.8S[196] notes that increasing depth of cover can be an effective method to prevent incidences of third-party damage, as Appendix A7 of ASME B31.8S notes that "agricultural lands with shallow depth of cover, may be more susceptible to third party damage." Appendix A9 of B31.8S includes the depth of frost line in the list of minimum data that should be collected

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[194] API RP 1133, "Guidelines for Onshore Hydrocarbon Pipelines Affecting High Consequence Floodplains," 1st edition, (February 2005).
[195] API RP 1160, "Managing System Integrity for Hazardous Liquid Pipelines," 3rd edition, February 2019.
[196] ANSI/ASME B31.8S, "Managing System Integrity of Gas Pipelines, Supplement to B31.8," 2004 edition, (January 1, 2005).

to assess the risk from the threat of weather or other outside force damage; if a pipe is buried below the frost line, the threat of frost heave is seriously reduced, directly tying the pipeline's current depth of cover to reduction of that threat.[197] Accordingly, Appendix A9 of ASME B31.8S recommends that if "a pipeline falls within the listed susceptibilities [for weather related and outside force threats], line patrolling should be used to perform surface assessments."

Proposals

PHMSA proposes modifications throughout § 195.412 for both carbon dioxide and hazardous liquid pipelines, including gathering lines. In paragraph (a), PHMSA proposes replacing "shall" with "must" for consistency with the majority of the language in part 195. For the reasons noted above, PHMSA also proposes that the inspections required by § 195.412(a) must be performed for the surface conditions of the right-of-way and adjacent areas to the right-of-way. This revises the word "or" to "and." Lastly, in paragraph (a), PHMSA proposes language stating that these inspections must examine the surface conditions for "indications of leakage, construction activity, geologic hazards, reduced depth of cover, and other factors that may affect pipeline integrity, safety, and operation." This codifies guidance from PHMSA advisory bulletins and industry best practices.

PHMSA also proposes the addition of § 195.412(c), which would require that when operators observe indications of geologic hazards on or adjacent to the pipeline right-of-way, they must perform certain preventative and mitigative actions. PHMSA proposes the operator

[197] ASME B31.8S notes that "lowering of the pipeline below the frost line for cold-weather situations" can be an effective preventative method to address the threat of frost heave. Source data on frost line depths are available online using data from Federal agencies, including the National Weather Service and National Oceanic and Atmospheric Administration.

must: (1) perform additional inspections and evaluations; (2) determine the extent of geologic hazards and their impact on the pipeline; and (3) take remedial action in accordance with § 195.401(b). These additional inspections and evaluations should be site-specific and may include field inspections by a geologic expert; in-line inspections using geometry tools with inertial measurement unit technology; aerial mapping light detection and ranging (LIDAR) or equivalent technology to track changes in ground conditions; and installation of monitoring equipment, such as standpipe piezometers, slope inclinometers, and strain gauges. Methods for determining the extent of geologic hazards and their impact may include detailed stress and strain analyses (including interpretation of in-line inspection data, field monitoring equipment, and metallurgical testing of equivalent girth welds) and engineering analyses performed by a qualified geologist or engineer with appropriate knowledge and expertise. PHMSA proposes that remedial actions for geologic hazards must be in accordance with § 195.401(b). Remedial actions may include installing drainage measures; reducing the steepness of unstable slopes through the use of mechanical structures; installing trench breakers and slope breakers; building retaining walls or equivalent structures; re-grading the pipeline right-of-way to minimize scour and erosion; bringing the pipeline above ground and placing it on supports that can accommodate large ground movements; reducing the operating pressure temporarily or shutting-in the affected pipeline segment completely; and re-routing the pipeline.

PHMSA also proposes the addition of § 195.412(d), which would require that when operators observe indications that depth of cover over a buried pipeline is less than that required at § 195.248, they must perform certain preventative and mitigative actions. PHMSA proposes that the operator must: (1) perform additional inspections and evaluations; (2) determine the extent of the reduced depth of cover and its impact on the pipeline; and (3) take remedial action, in accordance with § 195.401(b). These additional inspections and evaluations should be site-specific and may include depth-of-cover surveys; review of historical floodplain data to determine rate of scour; and aerial mapping light detection and ranging (LIDAR) or equivalent technology to track changes in ground conditions. Methods for determining the extent of reduced depth of cover and its impact should be site-specific and may include outreach to landowners, particularly of agricultural land, to determine tilling depths and depths of other activities that may reduce the depth of cover; and frost heave studies. PHMSA proposes that remedial actions for geologic hazards must be in accordance with § 195.401(b). These remedial actions should be site-specific and may include restoring depth of cover to the levels specified at § 195.248; re-grading the pipeline right-of-way to minimize scour and erosion; exposing and reburying the pipeline at a lower depth; reducing the operating pressure temporarily or shutting-in the affected pipeline segment completely; and re-routing the pipeline.

Additionally, PHMSA proposes at § 195.412(e) to require operators to maintain, for the life of the pipeline, all records of the following: inspections; evaluations; determinations of need for remedial action; and remedial actions performed under paragraphs (c) and (d) of § 195.412. Geologic hazards and the threat of reduced depth of cover may occur swiftly or over the course of several years, depending on the specific nature of the threat and the surrounding area. Maintaining a thorough history of data gathered in identification and evaluation of the threat(s), determinations made on the impact of the threat(s), and preventative and mitigative actions taken in response is crucial to the ability of an operator to make informed decisions and take appropriate actions to address these threats in the future. As noted above, several best practice documents recommend the use of this data as part of an effective IM program.

PHMSA expects the proposed amendments to inspection requirements pertinent to geologic hazards and the threat of reduced depth of cover would be reasonable, technically feasible, cost-effective, and practicable for hazardous liquid and carbon dioxide pipeline operators. PHMSA's proposed enhancements at § 195.412 are an incremental addition to existing inspection requirements along rights-of-way (at § 195.412) and following natural disasters and extreme weather events (at § 195.414). Maintaining records on the identification and evaluation of these threat(s), determinations made on the impact of the threat(s), and preventative and mitigative actions taken in response are also consistent with operator best practices for effective IM programs (pursuant to § 195.452) and common-sense tools for implementing lessons learned across an operator's assets. PHMSA understands that reasonably prudent operators employ industry standards and best practices even when not required by PHMSA regulations. Thus, PHMSA expects that the enhanced requirements for inspections, determinations of impact, and associated preventative and mitigative actions to reduce the risk of geologic hazards and the threat of reduced depth of cover, based on lessons learned, may already be observed voluntarily by reasonably prudent operators in order to protect the public, environment, and their commercially valuable product.[198] Should an operator of a carbon dioxide pipeline identify a compelling need for regulatory flexibility from these proposed requirements, the PSR provides for special permit procedures at § 190.341 to request a deviation.

[198] By way of example, several recent greenfield carbon dioxide pipeline projects voluntarily committed to enhanced right-of-way and post-natural disaster/extreme weather event inspections along the lines proposed here. See Navigator, S.D. Pub. Util. Comm. Doc. No. HP22-002, "Application for Permit to Construct the Navigator Heartland Greenway Project in South Dakota" at Exhibit D, PHMSA Exceedance Table (Sept. 27, 2022); Wolf Carbon Solutions, IL Commerce Comm. Doc. No. 23-0475, "Direct Testimony of Patrick Brierley for the Mt. Simon Project" at Exhibit 3.2 (June 16, 2023).

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 believes that operator compliance timelines based on an effective date of the proposed requirements one year after the publication date of a final rule—which would necessarily be in addition to the time since issuance of this NPRM—would provide affected operators ample time to implement requisite changed inspection practices and manage any related compliance costs.

2. Maintenance and Testing Requirements of Fixed Vapor Detection and Alarm Systems—§ 195.429

As discussed in section III.C.5, the first and third most prevalent accident causes reported on HVL pipeline systems (including carbon dioxide pipeline systems) from 2010 through 2022 were equipment failure and incorrect operation. Releases from HVL pipelines (including carbon dioxide pipelines) can present various hazards, including asphyxiation, toxicity, flammability, and combustibility, depending on the transported product and the presence of other constituents in the product stream. Releases on these systems caused by equipment failure and incorrect operation are most likely to occur at facilities where personnel may be present only intermittently, including pump or compressor stations, meter stations, valve stations, and other facilities, such as launcher and receiver sites. Depending on the release rate from a leak and the local conditions, personnel entering one of these facilities, whether they are enclosed spaces or not, may unknowingly enter a hazardous situation due to the accumulation of released product. In addition to personnel safety, leaks at facilities including pump or compressor stations, meter stations, valve stations, and other facilities, such as launcher and receiver sites, constitute a large volume of released product (see section III.C.5). As these sites may or may not be occupied by personnel, releases can continue for days or weeks before they are identified and corrected, resulting in a variety of potential environmental harms from the products released.

Accordingly, PHMSA is proposing the addition of a new § 195.263 to require, for all part 195-regulated pipelines transporting HVLs (including gathering lines and pipelines transporting carbon dioxide) that are newly constructed, replaced, relocated, otherwise changed, or converted to service on or after the effective date of a final rule, the use of fixed vapor detection and alarm systems at all pump stations, compressor stations, meter stations, and valve stations, to include launching and receiving facilities. In addition, PHMSA is also proposing at § 195.452(i)(5) to require operators of existing HVL pipelines (including carbon dioxide pipelines) to have fixed vapor detection and alarm systems meeting the requirements of the proposed § 195.263, at each pump station, compressor station, meter station, and valve station (including facilities for launching and receiving ILI tools or instrumented internal inspection devices) that are located in or could affect an HCA. (See section III.C.5 for further details on the specific operational requirements of these fixed vapor detection and alarm systems.)

As with all mechanical and electrical equipment, proper operation, maintenance, and testing of fixed vapor detection and alarm systems is critical to ensure the systems will function as designed. The absence of, or non-compliance with, written procedures for pipeline personnel to operate a fixed vapor detection and alarm system and procedures to respond to local or remote (e.g., from a control room) alarm indications could nullify the public safety and environmental benefits from installation of such a system. Lack of maintenance of and failure to thoroughly test for the proper operation of such a system could result in false alarms, or more worryingly, failure to detect a hazardous condition or properly alarm. Failure of a fixed vapor detection and alarm system to operate properly could cause harm to operator personnel entering the area, who might not otherwise be informed of the hazardous condition. Likewise, the lack of detection could result in an extended period of time before identification of the release, causing increased loss of product and potential additional harm to the environment. False alarms from improperly maintained and/or untested equipment also present costs, including diverting attention from legitimate alarms and the use of manpower and time.

Therefore, PHMSA is proposing the addition of a new § 195.429 to provide for the regular and proper maintenance and testing of fixed vapor detection and alarm systems required at §§ 195.263 and 195.452(i)(5). This proposal contains two requirements: (a) the operator must maintain each fixed vapor detection and alarm system to function properly; and (b) the operator must test each fixed vapor detection and alarm system under conditions approximating actual operations at least once per calendar year, but at intervals not exceeding 15 months. These annual tests must include tests of the individual components of the system and the entire system. These proposals allow the operator the flexibility to maintain the specific systems at their individual facilities according to manufacturer recommendations, while also ensuring the system is tested on a routine, annual basis to prove operability. PHMSA understands that operators would (pursuant to existing regulatory requirements at § 195.402) also need to update their written manuals for operations, maintenance, and emergencies to incorporate procedures on the operation, maintenance, and testing of their fixed vapor detection and alarm systems and responses to received alarms from those systems (both at the control room and locally).

PHMSA expects the proposed amendments regarding fixed vapor detection and alarm system maintenance and operation requirements described above would be reasonable, technically feasible, cost-effective, and practicable for carbon dioxide operators. PHMSA expects that integration of new procedures governing maintenance and operation of such systems into existing operator procedures would not be a significant burden on operators, who would be able to leverage maintenance and operational protocols developed by equipment manufacturers. Should an operator of a carbon dioxide pipeline identify a compelling need for regulatory flexibility from these proposed requirements, the PSR provides for special permit procedures at § 190.341 to request a deviation.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 believes that operator compliance timelines based on an effective date of the proposed requirements one year after the publication date of a final rule—which would necessarily be in addition to the time since issuance of this NPRM—would provide affected operators (specifically, for § 195.263, only HVL pipelines that are newly constructed, replaced, relocated, otherwise changed, or converted to part 195 service; and for § 195.452(i)(5), only HVL pipelines that could affect an HCA) ample time to implement requisite changes and manage any related compliance costs.

3. Conforming Changes—§§ 195.401, 195.404, 195.406, 195.434, 195.436, and 195.438

PHMSA proposes conforming changes in six sections of subpart F: §§ 195.401, 195.404, 195.406, 195.434, 195.436, and 195.438. These conforming changes fall into two general categories: (1) changes to accommodate the proposed definition change for carbon dioxide; and (2) changes to accommodate the proposed reorganization of another section.

Section 195.401 contains general requirements for part 195-regulated pipelines, whether they are transporting hazardous liquids or carbon dioxide. Paragraph (a) requires operators of hazardous liquid and carbon dioxide pipelines to operate and maintain their systems at a safety level meeting or exceeding that prescribed by subpart F and the procedures required by § 195.402(a). Paragraph (b) contains requirements for pipeline repairs.

Paragraph (c) restricts operators from operating pipelines that do not meet the design and construction requirements of part 195, except for certain historical pipelines and as provided at § 195.5. Simplified, this paragraph qualifies the default requirement at § 195.402(a) that all pipelines operated under part 195 must comply with part 195 design and construction requirements, unless construction on those pipelines had begun before PHMSA's part 195 regulations were first applied to that pipeline category or the pipeline was converted to part 195 service.[199] Subparagraphs (c)(1) through (c)(5) state the grandfather date for each pipeline category as follows: (1) interstate hazardous liquid (excluding low-stress pipelines); (2) interstate offshore gathering hazardous liquid (excluding low-stress pipelines); (3) intrastate hazardous liquid (excluding low-stress pipelines); (4) carbon dioxide; and (5) low-stress.

Notably, the reference to carbon dioxide at § 195.401(c)(4) refers to the existing definition of carbon dioxide: a fluid consisting of greater than 90 percent carbon dioxide molecules compressed to a supercritical state. As this NPRM proposes modifying the definition

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[199] In this case, "excepted pipelines" means pipelines in existence before PHMSA exercised its statutory authority to regulate those pipelines. PHMSA is restricted in which regulations it can apply retroactively to these pipelines.

of carbon dioxide, PHMSA expects there will be some existing pipelines that are transporting carbon dioxide meeting the newly proposed definition, but which are not currently subject to part 195 requirements. These pipelines include those transporting supercritical-phase carbon dioxide in percentages greater than 50 percent and equal or less than 90 percent carbon dioxide (e.g., 65 percent carbon dioxide) and those transporting carbon dioxide in either the gas or liquid phases.

Limitations on PHMSA's statutory authority[200] prevent PHMSA from applying the design and construction requirements of part 195 retroactively to pipelines newly subject to part 195 as proposed in this NPRM. As such, PHMSA proposes adding two new subparagraphs at § 195.401(c) and modifying subparagraph (c)(4).

Specifically, PHMSA proposes modifying subparagraph (c)(4) to further clarify that "carbon dioxide" in that subparagraph is consistent with the existing definition: a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state. Thus, pipelines transporting carbon dioxide with an excepted date of July 11, 1991, would be those transporting carbon dioxide in a supercritical state in a concentration of greater than 90 percent; this modification maintains the intent of the current part 195 language and the limitations of PHMSA statutory authority. Pipelines transporting all other carbon dioxide meeting the proposed new definition would have excepted dates defined at (c)(6)—in the supercritical phase and greater than 50 and less than or equal to 90 percent carbon dioxide—or (c)(7)—in the gas or liquid phase and greater than 50 percent carbon dioxide. Consistent with PHMSA's statutory authority and previous regulations, the excepted date for these pipelines at (c)(6) and (c)(7)

[200] 49 U.S.C. 60104(b).

would be the effective date of the eventual final rule for this NPRM. PHMSA considers these proposed changes as conforming changes for consistency with the proposed changes at § 195.2.

Section 195.404 requires operators to maintain maps and records of their pipeline systems, including pump stations. This NPRM proposes a conforming change at §195.404 by adding "compressor stations" to the list of facilities requiring signage, consistent with the addition of the gas phase to the definition of carbon dioxide at § 195.2.

Section 195.406 defines the maximum pressure at which part 195-regulated pipelines may operate, known as the MOP. Paragraph (a)(5) defines the MOP for pipelines that meet specific exception requirements at § 195.302(b); namely, those listed at § 195.302(b)(1) and (b)(2)(i). Section 195.302(b)(1) lists the exception requirements for various hazardous liquid pipelines, while § 195.302(b)(2) lists the exception requirements for various carbon dioxide pipelines. This NPRM proposes a conforming change at §195.406 by modifying the reference to "(b)(2)(i)" to "(b)(2)." This change would result in adding § 195.302(b)(2)(ii) and (b)(2)(iii) to the list of pipelines for which MOP may be defined by § 195.406(a)(5), as opposed to solely § 195.302(b)(1) and (b)(2)(ii). This would require newly regulated carbon dioxide pipelines under the proposed definition of carbon dioxide meeting the specific requirements of § 195.302(b)(2) to establish MOP in accordance with § 195.406(a)(5).

Section 195.434 requires signage at specific pipeline facilities, including pumping stations and breakout tank areas, and prescribes information that operators must include on this signage. This NPRM proposes a conforming change at §195.434 by adding "compressor stations" to the list of facilities requiring signage, consistent with the addition of the gas phase to the definition of carbon dioxide at § 195.2. As noted in section II.A, carbon dioxide is an asphyxiant; thus, it is prudent to provide the public with contact information for operators of compressor stations operating under part 195.

Section 195.436 requires operators to provide protection from vandalism of and unauthorized entry to various pipeline facilities, including pumping stations, breakout tank areas, and other exposed facilities. This NPRM proposes a conforming change at §195.436 by adding "compressor stations" to the list of facilities requiring protection from vandalism and unauthorized entry, consistent with the addition of the gas phase to the definition of carbon dioxide at § 195.2. As noted in section II.A, carbon dioxide is an asphyxiant; thus, it is prudent to protect compressor station facilities operating under part 195 from vandalism and unauthorized access to facility controls and equipment.

Section 195.438 prohibits smoking and open flames in each pump station area and each breakout tank area where flammable hazardous liquids or flammable vapors may be present. While carbon dioxide is non-flammable, compressor units operating on pipelines transporting gas-phase carbon dioxide can be powered by combustible materials, such as natural gas. Thus, flammable vapors may be present at compressor stations on gas-phase carbon dioxide pipelines. With the addition of gas phase to the definition of carbon dioxide, PHMSA proposes the addition of compressor stations to the list of areas where smoking and open flames are prohibited if flammable hazardous liquids or flammable vapors may be present.

PHMSA expects the proposed amendments would be reasonable, technically feasible, cost-effective, and practicable as they are clarifying in nature. As these changes will enhance an operator's understanding of the requirements and applicability of the sections, PHMSA expects the amendments to be welcomed by reasonably prudent operators. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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.

E. Enhanced Conversion to Service Requirements—§ 195.5

Requirements allowing pipelines previously not subject to part 195 to be used to transport hazardous liquids and carbon dioxide are contained at § 195.5. This is referred to as a conversion to service. Pipelines being converted in accordance with § 195.5 are those that have been previously constructed and placed in service not subject to part 195, and therefore, were possibly constructed, installed, tested, operated, and maintained in a manner different from pipelines designed and constructed for part 195 service.[201] The requirements for conversion to hazardous liquids service were added to part 195 in a final rule published on February 16, 1978.[202] At the time these requirements were published in 1978, most pipelines considered for conversion to service under part 195 were gas pipelines built before the design, construction, and testing requirements of the PSR were finalized and made effective for part 192-regulated gas pipelines in the early 1970s.[203,204]

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[201] An existing pipeline's voluntary conversion to part 195 service pursuant to § 195.5 is distinguishable from an existing pipeline becoming newly subject to part 195 requirements as a result of PHMSA's expansion of those requirements to additional pipelines (e.g., as PHMSA is proposing to do in this NPRM by its proposed amendment of regulatory definition of "carbon dioxide" at § 195.2). Similarly, a pipeline that is currently in part 195 service but whose operator voluntarily decides to change the commodity transported to carbon dioxide would not be subject to § 195.5 conversion of service requirements but would have to notify PHMSA of such a change, pursuant to § 195.64(c). See PHMSA, "Pipeline Safety: Guidance for Pipeline Flow Reversals, Product Changes and Conversion to Service" (Sept. 2014).

[202] 43 FR 6786 "Part 195 – Transportation of Liquids by Pipeline Conversion of Existing Pipelines to Liquid Service," (February 16, 1978).

[203] 35 FR 13248 "Part 192 – Transportation of Natural and Other Gas by Pipeline; Minimum Safety Standards," (August 19, 1970).

[204] 42 FR 18412: "Because most of the facilities that would be converted to liquid service were constructed prior to the controlling dates of § 195.402(d) [subsequently renumbered to become § 195.401(c)] in accordance with

All pipeline conversions are complicated, pipeline-specific projects requiring operators to review the design, construction, operations, and maintenance history of the pipeline and identify all known unsafe defects and conditions. Some of these conditions may be difficult to fully identify because the pipeline itself may have been installed decades previously and records may not be available. The conversion to part 195 service process at § 195.5, therefore, requires operators to prepare a written procedure to review the design, construction, and operating and maintenance history of the pipeline, and based on that review, perform any tests, and make any repairs, replacements, or alterations needed to determine if the pipeline is in satisfactory condition for safe operation. To ensure safety for conversion to service projects, PHMSA has relied on operator-determined "appropriate tests" where sufficient historical records are not available to determine if the pipeline is in satisfactory condition for safe operation.

Part 195 is currently silent on what those appropriate tests are. Instead, PHMSA has allowed operators to inspect and assess the pipeline segments being converted and determine what those appropriate tests are on a case-by-case basis. Operators have had the flexibility to prescribe the tests that they determined to be appropriate without a minimum standard for operators to meet during conversion to service projects. In addition to such operator-determined tests, operators must (pursuant to § 195.5(a)(2)) visually inspect the pipeline right-of-way, all aboveground segments, and appropriately selected underground segments for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline and correct all known unsafe defects and conditions. Operators must also perform

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specifications and procedures applicable at the time they were installed, they cannot realistically comply with all the design, construction, initial testing, and initial inspection requirements of Part 195."

leak and strength tests appropriate for the intended service to ensure that the pipeline will be serviceable and substantiate the MOP, and then commence operations in accordance with the preplanned procedure and other applicable sections of part 195.[205] After an operator has followed their written conversion-to-service procedure and accomplished the requirements prescribed at § 195.5 (unless another timeframe is noted - see § 195.5(b)), the pipeline is considered qualified for use under part 195 and can be placed into service by the operator. These conversion to service requirements have provided an alternative path for operators to bring pipelines into service under part 195 without requiring them to comply with all the current design, construction, initial testing, and initial inspection requirements that might not have been required for a pipeline at the time of its original construction.

The challenges associated with conversion of any pipeline to part 195 service could be magnified in the context of pipelines being converted to part 195 service transporting carbon dioxide. The limited mileage of existing (almost entirely supercritical-phase) carbon dioxide pipelines demonstrates relatively less operational experience with pipeline transportation of carbon dioxide than other hazardous liquid pipelines or gas pipelines; this warrants conservatism in the regulatory requirements imposed on conversion of pipelines to part 195 carbon dioxide service to address integrity risks that may emerge as the sector matures. Likewise, the variety of pathways from which existing pipelines may be converted to part 195 carbon dioxide pipeline service also supports enhanced conversion to service requirements for those pipelines. By way of example (and as discussed in section II.B), the expected rapid expansion of carbon dioxide

[205] 42 FR 18412, "Proposed Rule: Conversion of Existing Pipeline to Liquid Service," (April 7, 1977).

pipeline supporting CCUS applications is likely to result in some operators considering converting existing part 192-regulated gas and other pipelines to transport carbon dioxide under part 195 service. Standards development organizations for the pipeline industry have emphasized the need for special care when considering the re-use of existing pipeline infrastructure or oil and gas assets for transportation supporting CCUS, given that those pipelines were not specifically designed to handle carbon dioxide, which has a unique set of properties.[206] PHMSA also expects that many pipelines which operators may desire to convert to carbon dioxide service under part 195 may also have incomplete, inaccurate, or missing records due to periods of inactivity or unregulated service, or may have other reasons that records may not be available to the current operator of the pipeline (e.g., including divestitures or acquisitions). Similarly, those pipelines may also include a variety of historical materials, design features, construction techniques, and testing procedures that may inhibit efforts by PHMSA and State pipeline safety regulators to provide consistent regulatory oversight to ensure their operation in a manner protective of public safety and the environment.

Given the considerations outlined above, there is value in enhancing § 195.5 to strengthen its conversion to service requirements for all pipelines, with additional improvements specific to pipelines being converted to part 195 service transporting carbon dioxide.

Enhanced Design and Construction Requirements for All 195.5 Conversions

PHMSA proposes to explicitly require at a new subparagraph (a)(3) that any pipeline being converted to part 195 service (whether transporting hazardous liquid or carbon dioxide,

[206] See, e.g., Det Norske Veritas, "Safely re-using infrastructure for CO_2 transport and storage," (2022) https://www.dnv.com/Publications/safely-re-using-infrastructure-for-co2-transport-and-storage-229979.

and whether onshore or offshore) after the effective date of a final rule in this proceeding would need to comply with part 195 subparts C (design) and D (construction) requirements before the pipeline is placed into service as part of the conversion. Omission of such an explicit requirement from § 195.5 is an obsolete historical artifact; when PHMSA's predecessor agency in 1978 introduced the conversion to service requirements at § 195.5, such an omission was reasonable given the large inventory of pipelines that had been constructed prior to the codification of design and construction requirements at part 195 (as well as part 192). Since that time, the relative proportion of those legacy pipelines has decreased,[207] as new pipelines, whether originally intended for part 195 service or not, are often designed and constructed (as well as tested) in a manner compliant with then-effective part 192 or part 195 regulations. Requiring that pipelines newly converted to part 195 service meet the design and construction requirements of that part will ensure those pipelines incorporate current (rather than historical) safety-supporting design features and construction methods. For example, updating existing pipelines that are being considered for conversion to service to accommodate ILI tools (see § 195.120) and installing new valves or upgrading existing valves as needed to meet the current functional and location requirements (see §§ 195.258 and § 195.260) is just as critical for maintaining the integrity and safety of these newly converted pipelines as it is for maintaining the integrity and safety of newly constructed pipelines. Similarly, the convergence of design and construction

[207] Approximately 60 percent of hazardous liquid and carbon dioxide pipelines and 46 percent of gas pipelines have been designed, constructed, and placed in service subject to the PSR. See PHMSA, "Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data," https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

standards applicable to newly converted pipelines with those of newly constructed part 195-regulated pipelines would promote administrative efficiency in the regulatory oversight of all part 195-regulated pipelines by PHMSA and State pipeline safety regulators.

Complying with certain requirements under subparts C and D might not be realistic or practicable for a buried pipeline.[208] PHMSA provides an opportunity for operators to identify the requirements under subparts C and D that are impracticable and follow the procedure at § 190.341 to submit a special permit for PHMSA's approval. Operators that have executed, or are planning to execute, conversion to service projects are encouraged to comment on this proposal, including submitting historical project costs or future cost estimates. PHMSA also requests comments from operators on what, if any, design and construction provisions in subparts C and D are broadly unrealistic or impracticable for operators to comply with in their conversion to service projects of existing pipelines.

PHMSA expects the proposed amendments at § 195.5(a) to extend subparts C and D design and construction requirements to all conversion of service projects (as described above) would be reasonable, technically feasible, cost-effective, and practicable for affected hazardous liquid and carbon dioxide operators. Historical conversion to service projects would continue to be excepted from those requirements. And, as explained above, the historical exception of pipelines converted to part 195 service from subparts C and D design and construction requirements was appropriate at the time of § 195.5's codification a half-century ago; in the interim, the inventory of legacy pipeline candidates for conversion to part 195 service that have

[208] Examples of these requirements may include, depending on the specific circumstances: §§ 195.204, 195.207, 195.212, 195.228, 195.234, 195.248, and 195.266.

not been subject to any robust design and construction standards has diminished and will continue to decrease. Instead, pipelines built in subsequent years have generally been built consistent with the then-prevailing (and generally converging) consensus industry standards and PHMSA design and construction requirements (including those in subparts C and D of part 195). Additionally, PHMSA's anecdotal experience has been that operators considering conversions to part 195 service will generally perform upgrades on those pipelines to better align with part 195 design and construction requirements either as a compliance strategy pursuant to other applicable part 195 safety-enhancing requirements,[209] or as an exercise of business judgment to safeguard a commercially valuable commodity and minimize liability for public safety and the consequences of environmental harms from releases of that commodity.[210] That said, should an operator identify a compelling need for regulatory flexibility notwithstanding that trend, the PSR provides for special permit procedures at § 190.341 to request a deviation from specific subparts C and D design and construction requirements.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 believes that operator compliance timelines—based on an effective

[209] Including, but not limited to, requirements at § 195.5(a) (requiring correction of any unsafe condition, as well as verification of design pressure and determination of MOP prior to conversion) and § 195.452 (integrity management requirements for pipelines that could affect HCAs).
[210] By way of example in the context of carbon dioxide pipelines, industry guidance and technical documentation have recommended that conversion to service projects be designed and built to the same standards as greenfield projects. Pipeline Research Council International, Inc. (PRCI), "Pipeline Transportation of CO_2 SOTA, Gap Analysis and Future Project Roadmap" at 23 (Oct. 13, 2023); Det Norske Veritas (DNV), DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines at 26 (Sept. 2021).

date of the proposed requirements one year after the publication date of a final rule in this proceeding (which timeline would necessarily be in addition to the time since issuance of this NPRM)—would provide operators ample time to implement requisite changes and manage any related compliance costs and implementation challenges as they undertake new conversions to part 195 service.

Enhanced Requirements for Conversions to Part 195 Carbon Dioxide Service

PHMSA is also proposing to expand the tests and inspections that are required of pipeline operators electing to convert a pipeline previously used in service not subject to part 195 to transport carbon dioxide. Although PHMSA acknowledges that the current requirements at § 195.5 provide a baseline measure of safety for converted pipelines, those requirements provide only a limited, snapshot-in-time of select pipeline integrity considerations at the moment before pipelines enter part 195 service. By way of example, the requirement at § 195.5(a)(4) for operators to establish MOP on their pipeline conversions consists of a binary (pass/fail) assessment of pipeline integrity that incorporates conservatism with respect to potential threats to pipeline integrity. The required pressure test does not directly examine the pipeline to confirm the presence or absence of specific pipeline integrity threats (e.g., corrosion) that may not result in a failure of the pressure test, or which may emerge over extended time periods after conversion is complete due to different product stream composition, operating pressures, or other conditions. Although PHMSA understands that the snapshot-in-time information provided by the existing § 195.5 requirements (as amended to extend subparts C and D design and construction requirements consistent with this NPRM's proposals) would generally provide adequate assurance of pipeline integrity for hazardous liquids, conversions of pipelines to part 195 carbon dioxide service involve potentially different risks. As discussed above, PHMSA anticipates the incentives surrounding carbon dioxide transportation may bring a variety (in terms of pipeline vintage, design features, construction materials and methods, testing procedures, and quality of supporting documentation and records) of existing pipelines under part 195 carbon dioxide service, therefore calling for additional measures to ensure the safety of those pipelines. These proposed additional, carbon dioxide-specific tests and inspections include performing spike hydrostatic pressure testing performed in accordance with proposed § 195.309[211]; performing close interval and pipeline coating surveys (including alternating current voltage gradient (ACVG), direct current voltage gradient (DCVG), or other technology)[212]; assessing the integrity of the line pipe by ILI; as well as an explicit requirement within those new provisions for remediation of any deficiencies or conditions identified by those tests, inspections, and assessments that could adversely affect the safe operation of the pipeline. PHMSA proposes that some of these new requirements would be conditions precedent for conversion under § 195.5; others proposed requirements would need to be satisfied after a carbon dioxide pipeline has been placed in service under part 195 to allow time to identify emerging pipeline integrity risks resulting from the pipeline's new product stream composition and operating conditions.

First, PHMSA is proposing supplemental language at the existing § 195.5(a)(4) (which this NPRM proposes to redesignate as § 195.5(a)(5)) to require all pipelines converted to part 195 carbon dioxide service be spike tested before conversion. As discussed in the 2019 final rule

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[211] PHMSA expects that operators will perform such spike hydrostatic testing before introducing carbon dioxide into the pipeline, thereby eliminating the need to blow down the pipeline before the testing.
[212] ACVG and DCVG are specialized types of coating surveys.

that standardized the requirements for "spike" hydrostatic testing for gas pipelines,[213] ongoing research and industry response to the advance notice of proposed rulemaking (ANPRM)[214] and NPRM[215] for that final rule indicate that ILI and spike hydrostatic testing are effective methods for identifying pipe conditions that are related to stress corrosion cracking and other cracking or crack-like defects. As proposed at § 195.309 and discussed in section III.C.7, the spike test consists of temporarily increasing the pressure of the test medium to a level beyond what is normally required to establish the MOP or assess the integrity of the pipe (i.e., raising the test pressure from a pressure equal to or greater than 125 percent, or more, of the MOP to a pressure that is the lesser of 150 percent, or more, of the MOP or 100 percent of the SMYS of the pipeline segment being tested.) This higher test pressure is held for a period of at least 30 minutes, after which the pressure is lowered back to the baseline test pressure for the remainder of the specified test duration. Performing this additional, more stringent testing would ensure the pipeline segment being converted to transport carbon dioxide is qualified for use under part 195 and would assure the public that the converted pipeline, which might have incomplete design, construction, operations, and maintenance records, is fit for service with the new commodity. As such, PHMSA is proposing that operators converting pipeline segments to transport carbon dioxide under part 195 perform this additional test to ensure a higher margin of safety when determining the starting condition and integrity of the pipeline, considering the mounting interest

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[213] "Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments,"84 FR 52180; October 1, 2019.
[214] "Pipeline Safety: Safety of Gas Transmission Pipelines—Advance Notice of Proposed Rulemaking," 76 FR 5308; August 25, 2011.
[215] "Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines," 81 FR 20722; April 8, 2016.

in rapid development and operation of CCUS infrastructure.

Second, PHMSA is proposing a new subparagraph (c) to require operators converting pipelines to transport carbon dioxide under part 195 to perform close interval and pipeline coating surveys within 15 months of placing the converted pipeline into service. PHMSA has proposed in this NPRM a new definition for "close interval survey," or CIS (see section III.A.3) to mean a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops[216] other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey. In cases where the effectiveness of a cathodic protection (CP) system of a pipeline has degraded or is uncertain (e.g., due to neglect during periods of pipeline inactivity; or incomplete design, construction, operations, and maintenance records), CIS can help identify where the CP system needs to be updated or upgraded, where additional test stations need to be installed, and where investigatory pipeline examinations for external corrosion would be prudent. CIS can also identify systemic causes of inadequate CP that can affect the integrity of the pipeline.

PHMSA understands that CIS can be a helpful tool in understanding the operation and condition of the CP system and pipeline coating condition; however, the agency expects there to be instances where CIS is not possible for geographical, technical, or safety reasons. As proposed in § 195.5(c)(1), PHMSA would allow the operator to make such a determination and

[216] IR drop refers to the voltage drop across any resistance, which is the product of current (I) passing through resistance with a resistance value (R).

not perform the CIS, if the operator documents that determination as part of their written conversion to service procedure.

At proposed § 195.5(c)(2), PHMSA proposes a 15-month timeframe for performing the CIS. That timeline is similar to the longstanding requirement at § 195.5(b) that an operator of converted pipelines need not comply with the corrosion control requirements of subpart H of this part until 12 months after the converted pipeline is placed into service. Should operators use the full 12 months allowed to comply with subpart H requirements at § 195.5(b), operators would have no more than 3 additional months to perform the CIS for the entire length of the converted pipeline segment. PHMSA expects that operators of pipelines being converted to transport carbon dioxide will not need the full 12 months allowed by § 195.5(b) and will be able to perform the CIS earlier than the full timeframe allowed, possibly prior to placing the converted pipeline into service.

Alongside the requirement to perform a CIS at § 195.5(c), PHMSA is proposing to implement a remediation requirement associated with the required CIS. Section 195.5(c)(2) would require the operator to promptly correct any deficiencies indicated by CIS by developing a remedial action plan and applying for any necessary permits within 6 months of completing the CIS. The operator would then be required to complete the remedial action promptly, but no later than the earliest of the following: within 12 months of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

Third, PHMSA is proposing at a new subparagraph (d) that each operator of a pipeline converted to part 195 service to transport carbon dioxide after the effective date of a final rule must perform pipeline coating surveys to assess any coating damage and ensure the integrity of the coating using DCVG, ACVG, or other technology that provides comparable information about the integrity of the coating. Like the timeframe for CIS described above, coating surveys of the pipeline must be performed no later than 15 months after placing the converted pipeline into service, unless the operator determines and documents that effective coating surveys are not possible for geographical, technical, or safety reasons. PHMSA is also proposing to allow an operator to notify PHMSA in accordance with § 195.18 at least 90 days in advance of using other technology to perform the pipeline coating surveys. After pipeline coating surveys are performed, PHMSA is proposing that each operator must repair any coating damage indicated by a voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG in accordance with the timeframe and requirements proposed at § 195.5(c)(2), which would require the operator to promptly correct any deficiencies indicated by pipeline coating surveys by developing a remedial action plan and applying for any necessary permits within 6 months of completing the pipeline coating survey.[217] The operator would then be required to complete the remedial action promptly, but no later than the earliest of the following: within 12 months of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

Fourth, PHMSA is proposing at a new subparagraph (e) that each operator of a pipeline being converted to part 195 service to transport carbon dioxide following the effective date of a

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[217] PHMSA is proposing these prescriptive thresholds for severe coating damage, indicated by a voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG, pipeline coating surveys. These limits are found elsewhere in the PSR (*see* 87 FR 52224: Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (August 24, 2022) (RIN2 Final Rule).

final rule must assess the integrity of the line pipe by ILI as described at §§ 195.416 and 195.452, as applicable, for the range of relevant threats to the pipeline segment. PHMSA is proposing that this assessment must be performed within 12 months after placing the converted pipeline into service. This assessment will serve as an additional measure, in concert with the other requirements PHMSA is proposing at § 195.5, to determine the starting condition and integrity of the converted pipeline. Regarding any anomaly that is discovered during the assessment performed under this paragraph, PHMSA proposes to require each operator to follow the requirements at § 195.401 if the operator finds a condition that could adversely affect the safe operation of a pipeline. At § 195.401, an operator must make repairs on its pipeline system according to the location of the pipeline segment, with repairs on segments covered by the IM program at § 195.452 being performed in accordance with § 195.452(h) and repairs on segments not covered under the IM program being performed in accordance with § 195.401(b)(1).[218] In all cases, whether covered or not under the IM program, an operator must consider the risk to people, property, and the environment when prioritizing the correction of any conditions referenced above.

PHMSA expects the proposed amendments enhancing conversion to service requirements specific to carbon dioxide pipelines described above would be reasonable, technically feasible, cost-effective, and practicable for affected operators. The proposed amendments build on a longstanding PSR requirement at § 195.5(a)(3) to correct any unsafe defects and conditions

[218] § 195.401(b)(1): "Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time. However, if the condition is of such a nature that it presents an immediate hazard to persons or property, the operator may not operate the affected part of the system until it has corrected the unsafe condition."

before conversion to part 195 service by specifying the minimum requirements for verification of the integrity of carbon dioxide pipelines. Meanwhile, the proposed spike testing requirement at subparagraph (a)(5) also builds on longstanding design pressure verification and MOP determination requirements at § 195.5(a)(1) and (5) that are required actions prior to conversion to part 195 service; spike testing can be integrated into any necessary pre-conversion pressure testing protocols with limited additional burden for operators. Similarly, the proposed corrosion control measures at § 195.5(c) (requiring CIS to evaluate the effectiveness of cathodic protection systems used to prevent external corrosion) and 195.5(d) (requiring surveys of external anti-corrosion coating) complement a longstanding post-conversion requirement at § 195.5(b) governing timelines for compliance with subpart H corrosion control requirements; PHMSA's proposed CIS and coating survey requirements remain required actions after conversion, and align with part 192 requirements for PHMSA-regulated gas pipelines regarding coating damage classification thresholds (§ 192.319) and permitting and repair timelines (§ 192.473)—both of which were informed by consensus industry standards. Additionally, PHMSA's proposed requirement for post-conversion ILI assessment of pipeline integrity aligns with industry guidance for all carbon dioxide pipelines to identify potential corrosion, as well as the practice of reasonably prudent operators of greenfield carbon dioxide projects who have committed to perform ILI assessments of their pipelines, given the potential lost commercial value and hazards to public safety and the environment from releases from their pipelines.[219] Should an operator of

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[219] See Det Norske Veritas (DNV), DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines at 69-71 (Sept. 2021); Navigator, S.D. Pub. Util. Comm. Doc. No. HP22-002, "Application for Permit to Construct the Navigator Heartland Greenway Project in South Dakota" at Exhibit D (Sept. 27, 2022); Wolf Carbon Solutions, IL

a carbon dioxide pipeline identify a compelling need for regulatory flexibility from these proposed requirements, PHMSA's proposed amendments at § 195.5 allow some flexibility for operators if performing CIS and external coating surveys are not possible for documented safety, geographical or technical reasons; Also, the PSR provides for special permit procedures at § 190.341 to request a deviation from any of the requirements governing conversion to part 195 service.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed amendments discussed above 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 believes that its proposed compliance timeline (based on an effective date of the proposed requirements one year after the publication date of a final rule—which would necessarily be in addition to the time since issuance of this NPRM) would provide affected operators ample time to manage any related compliance costs and implementation challenges as they undertake conversion of their pipelines to part 195 service.

F. Enhanced Emergency Response and Communications—§§ 195.402 and 195.403

Overview

Part 195 requires operators to have written procedures for responding to emergencies involving their pipeline system to ensure a coordinated response to a pipeline emergency. This response includes communicating with fire, police, and other public officials promptly in the

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Commerce Comm. Doc. No. 23-0475, "Direct Testimony of Patrick Brierley for the Mt. Simon Project" at Exhibit 3.2 (June 16, 2023).

event of an emergency and establishing communications with emergency response organizations for mutual preparedness. PHMSA most recently enhanced those requirements through a final rule issued in April 2022, entitled "Requirement of Valve Installation and Minimum Rupture Detection Standards" (Valve Rule), by extending the emergency communication requirement for all hazardous liquid and carbon dioxide pipeline operators to include a public safety answering point (PSAP; i.e., 9-1-1 emergency call center).[220] Specifically, the Valve Rule amended § 195.402(c)(12) and 195.402(e)(7) in several respects to ensure proper communication with PSAPs, requiring operators to establish and maintain adequate means of communication with PSAPs, and to immediately and directly notify PSAPs upon notification of a potential rupture.

PHMSA, in this NPRM, proposes building on the Valve Rule's changes to emergency response plan requirements through additional measures to ensure prompt and effective emergency response coordination and address the unique risks to public safety and the environment posed by pipeline transportation of carbon dioxide. Those risks were underscored by the 2020 Satartia accident; inadequate emergency response figured prominently in PHMSA's failure investigation report, which found that the operator did not promptly notify local emergency responders of the carbon dioxide release on their pipeline or establish appropriate communication prior to the accident with all organizations that responded to the accident.

First, PHMSA proposes additional training for emergency responders. PHMSA proposes that carbon dioxide pipeline operators provide local emergency response organizations with equipment, instruments, tools, and materials needed to respond to an emergency on a carbon

[220] 87 FR 20940, 20973. The NPRM preceding the Valve Rule published in February 2020, a few months before the Satartia accident.

dioxide pipeline and train those personnel on the proper use of such equipment, instruments, tools, and materials. PHMSA also proposes the addition of asphyxiation as a condition for which operator response personnel should be trained on mitigation methods.

Second, PHMSA proposes requirements for additional safety equipment. In this NPRM, PHMSA proposes that all hazardous liquid and carbon dioxide pipeline operators provide additional safety equipment in excavated trenches. PHMSA also proposes that hazardous liquid and carbon dioxide operators have appropriate equipment to detect hazardous concentrations of vapor and gas, including known deleterious constituents in the product stream.

Lastly, this NPRM proposes that carbon dioxide pipeline operators must communicate with the affected entities, including the general public (using data collected from population density surveys conducted at proposed §§ 195.210 and 195.402(c)(17)) during an emergency to inform them of the emergency and provide public safety information, coordinating with emergency response organizations for a consistent and clear message to the public.[221] The sections below discuss each of these proposals in more detail.

1. Expanded Emergency Responder Training—§§ 195.402(c)(16) and 195.403(a)(4)

Section 195.402(c) requires that each hazardous liquid and carbon dioxide pipeline operator have written procedures for performing maintenance activities and normal pipeline operations, including how operators are expected to communicate with fire, police, and other

[221] The proposed requirements at §§ 195.210 and 195.402(c)(17) will require each operator of a carbon dioxide pipeline to perform a population density survey to understand and catalog the locations and needs of the public that are located within an emergency planning zone (two miles on either side of the pipeline) to inform their pre-emergency public awareness initiatives and facilitate emergency response efforts in the event of an emergency on the pipeline.

appropriate public officials before an emergency.

As noted in section II.A, carbon dioxide is colorless, odorless, asphyxiating, and denser than air. These characteristics present unique threats not exhibited by other commodities transported under part 195.[222] In addition, certain potential constituents of carbon dioxide product streams, including hydrogen sulfide, can themselves present serious environmental and health risks. Section 195.402(c)(12) currently requires operators to maintain adequate communications with PSAPs; determine the responsibilities, resources, jurisdictional area(s), and emergency contacts for each Federal, State, and local government organization that may respond to a pipeline emergency; and inform the officials about the operator's ability to respond to the pipeline emergency and means of communication during emergencies. This section does not require any specific training on the equipment, instruments, tools, and materials necessary when responding to an emergency. Local emergency response organizations, especially those in disadvantaged or low-income areas, may be less familiar with carbon dioxide pipeline emergencies and the proper equipment, instruments, tools, and materials necessary for responding to such events. Thus, filling this knowledge gap by requiring operators of carbon dioxide pipelines, who are best positioned to have expertise and familiarity with carbon dioxide pipeline emergency response, to train local emergency response personnel on how to use the equipment, instruments, tools, and materials necessary when responding to a carbon dioxide pipeline emergency is prudent both for emergency responder safety and public safety. Some

[222] "Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document; Guidelines for Preparedness and Initial Response to a Pipeline Release of Carbon Dioxide (CO_2)", API, Liquid Energy Pipeline Association, and National Association of State Fire Marshals; (August 2023) pp. 6.

emergency response organizations may not be equipped with these devices;[223] thus, emergency responders may be unfamiliar with their proper use. Needed equipment, instruments, tools, and materials for a carbon dioxide pipeline emergency can be costly. Local emergency response organizations, many staffed primarily by volunteers, may not have sufficient resources to acquire the needed equipment, instruments, tools, and materials to respond properly to an emergency on a carbon dioxide pipeline.

For these reasons, PHMSA is proposing a new paragraph at § 195.402(c)(16) that would require carbon dioxide pipeline operators to provide local[224] emergency response organizations with the equipment, instruments, tools, and materials necessary for responding to an emergency on a carbon dioxide pipeline. Depending on the circumstances of the emergency, this may include, but is not limited to: (1) personal safety devices, such as breathing apparatuses and fire-resistant clothing, (2) detection and monitoring equipment, such as air monitoring devices and lower-explosive level detectors, (3) clean-up materials, such as absorbent materials and roll-off boxes, (4) containment equipment, such as booms, (5) access materials, such as gravel and mats, and (6) other equipment, instruments, tools, and materials, as needed. This would also include devices capable of detecting hazardous concentrations of carbon dioxide and any deleterious constituents in the product stream, as required at § 195.402(e)(3); hazardous concentrations

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[223] Information on specific examples of these devices can be found in Section III.F.2 of this NPRM.

[224] PHMSA envisions that "local emergency response organizations" as used at proposed § 195.402(c)(16) would refer to any organizations (including county, regional, tribal, and local organizations) obliged to respond to an emergency on a carbon dioxide pipeline that could affect areas within the 2-mile emergency planning zone required at § 195.402(c)(17). This understanding could refer in practice to emergency response organizations that are themselves beyond 2 miles away from the pipeline (e.g., pursuant to a mutual aid agreement or understanding, or if a portion of the emergency response organization's geographic area of responsibility overlaps the emergency planning zone).

would include concentrations of carbon dioxide or other constituents in the product stream that could asphyxiate, intoxicate, or otherwise injure exposed individuals. In addition, PHMSA is proposing that carbon dioxide pipeline operators would be required to train local emergency response personnel on how to use the provided equipment, instruments, tools, and materials when responding to an emergency on a carbon dioxide pipeline, in accordance with § 195.440.

In addition to communicating with and training emergency response personnel, pipeline operators are required to train their employees on emergency response actions. Section 195.403 requires operators of hazardous liquid and carbon dioxide pipelines to establish a continuing training program for operator emergency response personnel. Paragraph (a) and its following subparagraphs outline the required topics for which the operator must provide instruction, including performance of emergency procedures, recognition of conditions that may cause emergencies, and knowledge of important characteristics and hazards of the transported product. Section 195.403(a)(4) lists four conditions (fire, explosion, toxicity, environmental damage) that present hazards to human life or the environment. Operators are required to train their personnel on how to take action to minimize the potential occurrence of these four conditions.

As noted in section II.A, carbon dioxide is an asphyxiant. Besides carbon dioxide, other commodities transported in hazardous liquid pipelines can also lead to asphyxiation if released.[225] Therefore, PHMSA proposes adding asphyxiation to the list of conditions at § 195.403(a)(4) that would require operators of carbon dioxide and hazardous liquid pipeline systems to train their emergency response personnel on the necessary steps to minimize the

[225] https://www.chemscape.com/resources/chemical-management/health-hazards/asphyxiation

potential for asphyxiation in the event of an accidental release.

PHMSA expects the proposed amendments at §§ 195.402 and 195.403 discussed above would be reasonable, technically feasible, cost-effective, and practicable enhancements of existing PSR requirements for affected hazardous liquid and carbon dioxide operators. As explained above, PHMSA's proposed amendment at § 195.403 of the longstanding requirement for operators to train their own personnel simply clarifies a principal hazard of carbon dioxide pipelines. Similarly, the PSR has a longstanding requirement at § 195.402(d)(3) for operators of all part 195-regulated pipelines to have "equipment, instruments, tools, and materials" as needed at the scene of an emergency; the new § 195.402(c)(16) would extend that obligation to provide necessary "equipment, instruments, tools, and materials" to local emergency response organizations who may prove better-positioned to mitigate the public safety and environmental consequences of a carbon dioxide pipeline emergency than operator personnel. PHMSA proposes drawing narrowly on the proposed language at § 195.402(c)(16) to minimize the burden on affected carbon dioxide operators. In addition to limiting the geographic scope of the provision and training requirements by tying these proposals to the emergency planning zone proposals elsewhere in this NPRM, PHMSA has borrowed language from § 195.402(e)(3) defining the scope of equipment, instruments, tools, and materials provided to those which would be strictly necessary for responding to an emergency. Also, operators whose carbon dioxide pipelines could affect an HCA may be able to integrate within their § 195.452-compliant IM programs any equipment, instruments, tools, materials, and training they provide when complying with the proposed § 195.402(c)(16). PHMSA also understands that some operators of planned greenfield carbon dioxide pipeline projects have voluntarily committed during state permitting proceedings[226] to provide emergency response equipment and training to local emergency response officials, demonstrating that the proposed requirement in the NPRM is consistent with measures reasonably prudent operators of carbon dioxide pipelines would undertake in ordinary course given the potential lost commercial value and hazards to public safety and the environment from releases from their pipeline projects. Should an operator of a carbon dioxide pipeline identify a compelling need for regulatory flexibility from these proposed requirements, the PSR provides for special permit procedures at § 190.341 to request a deviation.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed amendments discussed above 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 believes that its proposed compliance timeline (based on an effective date of the proposed requirements one year after the publication date of a final rule—which would necessarily be in addition to the time since issuance of this NPRM) would provide affected operators (specifically, carbon dioxide pipeline operators) ample time to manage any related compliance costs and implementation challenges.

2. Expanded Emergency Response Equipment and Instrumentation Requirements—§§ 195.402(c)(14), 195.402(e)(3), and 195.402(e)(8)

Section 195.402(c) requires that each hazardous liquid and carbon dioxide pipeline

[226] See, e.g., Gerlock, Iowa National Public Radio, "Plans for Carbon Dioxide Pipelines Raise Safety Concerns for Small Town Responders in the Midwest" (Oct. 6, 2023.) (Noting that both the Navigator and Summit Carbon Solutions had committed to providing local emergency responders with emergency equipment and training). *https://nebraskapublicmedia.org/en/news/news-articles/plans-for-carbon-dioxide-pipelines-raise-safety-concerns-for-small-town-responders-in-the-midwest/*

operator have written procedures for performing maintenance activities and normal pipeline operations. These procedures must include taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas. This requirement applies for excavated trenches in normal maintenance and operations activities. Section 195.402(c)(14) also requires that operators make available emergency rescue equipment, including a breathing apparatus, and a rescue harness and line, when needed. Unsafe accumulations of vapor or gas are those which could asphyxiate, intoxicate, or otherwise injure exposed employees, or concentrate to a point where ignition is possible.

Excavated trenches are spaces with limited access points, which can make entering and exiting them when releases or emergencies occur more difficult, and thus, take more time. Decision-making on precisely what emergency rescue equipment is needed as work commences can be dependent on whether personnel are entering a trench that already has hazardous concentrations of vapors and gases. After work commences, recovering injured individuals in excavated trenches can present an additional threat to those operator or emergency response personnel entering the hazardous environment. Therefore, making equipment available to detect hazardous conditions and control fires is prudent for both preventing injuries in excavated trenches and reducing their severity. PHMSA proposes to add on-site fire control equipment and devices capable of detecting hazardous concentrations of vapor or gas to the list of equipment operators should make available in excavated trenches, when needed.

Equipment requirements for emergencies, as opposed equipment requirements for normal operations and maintenance, are detailed at § 195.402(e). This section requires that each hazardous liquid and carbon dioxide pipeline operator have written safety procedures for emergencies, including required response and safety equipment. Section 195.402(e)(3) requires that hazardous liquid and carbon dioxide pipeline operators have personnel, equipment, instruments, tools, and materials available as needed at the scene of an emergency. Depending on the circumstances of the emergency, this may include, but is not limited to: (1) personal safety devices, such as breathing apparatuses and fire-resistant clothing, (2) detection and monitoring equipment, such as air monitoring devices and lower-explosive level detectors, (3) clean-up materials, such as absorbent materials and roll-off boxes, (4) containment equipment, such as booms, (5) access materials, such as gravel and mats, (6) heavy machinery, such as excavators, (7) specialized pipeline tools, such as stopples, and (8) technical response personnel, including technicians, welders, and environmental specialists, among other personnel, equipment, instruments, tools, and materials, as needed. Section 195.402(e)(8) further specifies that operators of HVL pipelines, in addition to the instruments required at the scene of an emergency in accordance with § 195.402(e)(3), are also required to use instruments to assess the extent and coverage of the vapor cloud and determine the hazardous areas. Hazardous areas are locations where the vapor cloud(s) could asphyxiate, intoxicate, or otherwise injure exposed persons, or where ignition is possible.

Carbon dioxide is asphyxiating, and constituents of some carbon dioxide streams, including hydrogen sulfide, are flammable and toxic. All supercritical- and liquid-phase carbon dioxide pipelines operate above atmospheric pressure, and those planned gas-phase carbon dioxide pipelines of which PHMSA is knowledgeable are projected to operate above atmospheric pressure. When carbon dioxide pipelines operate above atmospheric pressure, releases result in rapidly expanding vapor clouds. These vapor clouds are colorless and odorless, which makes obtaining information on the location, extent, and concentration of vapor clouds highly unlikely without specialized tools and instruments.[227]

For these reasons, PHMSA is proposing at § 195.402(e)(3) to specify that hazardous liquid and carbon dioxide pipeline operators must have tools and instruments capable of detecting flammable, asphyxiating, or toxic concentrations of hazardous liquid or carbon dioxide, as well as known deleterious constituents in the product stream, available at the scene of an emergency. This proposal would be in addition to the preexisting requirement for all hazardous liquid and carbon dioxide pipeline operators to have personnel, equipment, instruments, tools, and material available as needed at the scene of an emergency.

Lastly, PHMSA is proposing a conforming change at § 195.402(e)(8) by adding in a parenthetical that carbon dioxide is included as an HVL, and therefore the requirements of § 195.402(e)(8) would also apply to carbon dioxide pipeline operators. Thus, operators of carbon dioxide pipelines would also be required to use appropriate instruments to assess the extent and coverage of vapor clouds and determine hazardous areas in the event of a failure. This change conforms with the change in the definition of HVL proposed at § 195.2.

PHMSA expects the proposed amendments to § 195.402 discussed above would be reasonable, technically feasible, cost-effective, and practicable enhancements of the existing PSR requirements for affected hazardous liquid and carbon dioxide operators. PHMSA's proposed amendments at §§ 195.402(c)(14) and 195.402(e)(3) are common-sense elaborations on longstanding regulatory language ("adequate precautions" at § 195.402(c)(14); and "equipment,

[227] Some minor constituents in carbon dioxide product streams, such as hydrogen sulfide, can produce a smell and odor, but the visibility of such constituents in the vapor clouds can be inconsistent or difficult to observe, and these constituents are dangerous to inhale for the purposes of identification by smell.

instruments, and tools" at § 195.402(e)(3)), specifying that among the equipment, instruments, and tools operators should make available as needed are detectors to alert personnel of hazards both as they enter or work in an excavated trench, as well as when they respond to a pipeline emergency. PHMSA expects that reasonably prudent operators will already employ such equipment in ordinary course given the risks to their own and contractor personnel; indeed, such existing efforts would align with operations, maintenance, and emergency response safety principles enumerated in consensus industry standards as well as other Federal and State requirements.[228] Similarly, the proposed amendment at § 195.402(e)(8) to explicitly include carbon dioxide pipelines within the scope of that longstanding requirement would conform to and backstop (by codification as a legal obligation) the existing practice of reasonably prudent carbon dioxide pipeline operators, as well as recent industry-endorsed emergency response strategies emphasizing the value of real-time detection capabilities.[229] Also, should an operator identify a compelling need for regulatory flexibility, the PSR provides for special permit procedures at § 190.341 to request a deviation from specific regulatory requirements.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 believes that operator compliance timelines (one year after the

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[228] See, e.g., 29 CFR 1910.119 (OSHA process hazard analysis requirements); API, Liquid Energy Pipeline Association, and National Association of State Fire Marshals; (August 2023) pp. 22-25; API, "Recommended Practice RP 1173: Pipeline Safety Management Systems" at pp. 1 (July 2015).

[229] Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document; Guidelines for Preparedness and Initial Response to a Pipeline Release of Carbon Dioxide (CO_2)", API, Liquid Energy Pipeline Association, and National Association of State Fire Marshals at pp. 22-24 (August 2023).

publication date, which would necessarily be in addition to the time since issuance of this NPRM) would provide operators ample time to implement requisite changes and manage any related compliance costs and implementation challenges.

3. Additional Communication with Affected Entities—§§ 195.402(c)(17) and 195.402(e)(9)

The initial effects of most pipeline ruptures, including those on pipelines transporting carbon dioxide, hazardous liquid, and natural or other gases, are often energetic and involve an initial explosion followed by the sound of pressurized product escaping from the pipeline. To the public that might be near the pipeline at the time of rupture, these events can be observed and recognized quickly, regardless of the product being transported. However, carbon dioxide has physical characteristics that lead it to be transported to locations well beyond the distance at which the general public would see or hear indications of the initial rupture. Other types of emergencies on pipeline systems, such as overpressure events and equipment failure, may be even more difficult for the public to identify. While most other products transported under part 195 produce visible signs of a release or an easily recognizable odor, carbon dioxide is both odorless and colorless.[230] Natural gas, which is also naturally odorless and colorless, is often transported near and through populated areas with an odorant to aid in the detection of smaller

[230] "Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document; Guidelines for Preparedness and Initial Response to a Pipeline Release of Carbon Dioxide (CO_2)", API, Liquid Energy Pipeline Association, and National Association of State Fire Marshals; (August 2023). Released plumes of carbon dioxide might create a cloud of condensed water vapor due to the cold temperatures caused by the rapid expansion of the carbon dioxide as it leaves the pipeline, but the extent of the hazardous concentrations of carbon dioxide within the actual carbon dioxide plume might not correspond to the extent of the condensed water vapor cloud and could reach the public without any sign or warning.

releases and leaks. In addition, in the event of a pipeline rupture or other emergency, the released natural gas is naturally buoyant in the surrounding air, and thus not likely to be transported over large a distance at the ground level where it could affect an unaware public. There is no commercially available odorant approved for use in carbon dioxide pipeline systems and no existing guidance or industry standards on odorizing carbon dioxide pipelines. Studies note that "further investigation is needed into the interaction of specific impurities associated with captured CO_2" with odorants, as well as how different phases of carbon dioxide may affect odorization.[231] Some constituents of carbon dioxide product streams, such as hydrogen sulfide, can produce a smell and faint visible color; however, these constituents are unreliable for detecting carbon dioxide vapor clouds and present their own health and safety risks. Without the ability to odorize carbon dioxide, the only reliable method for the public to identify carbon dioxide vapor clouds and potentially hazardous concentrations of carbon dioxide within those clouds are carbon dioxide detectors. While carbon dioxide detectors are commercially available to individual consumers, they are cost-prohibitive for many families (costs are upwards of $250 per detector), and since carbon dioxide is a normal component of air, those consumer detectors are typically designed for monitoring purposes, not alarm purposes (as opposed to a carbon monoxide or smoke alarm detector). Maximum detection capabilities for commercially available, residential carbon dioxide detectors can be as low as 1,200 ppm (well below concentrations that can cause asphyxiation) and are only intended for use in small, enclosed spaces, such as

[231] R. Kilgallon, S.M.V. Gilfillan, R.S. Haszeldine, C.I. McDermott, "Odourisation of CO_2 pipelines in the UK: Historical and current impacts of smell during gas transport," International Journal of Greenhouse Gas Control, https://doi.org/10.1016/j.ijggc.2015.04.010.

bedrooms or offices.

Without a readily available method of detection at their disposal, the public is entirely reliant on information provided to them by others to know when emergencies that could affect public safety occur on carbon dioxide pipelines. While the primary responsibility for informing the public about pipeline emergencies in their area, including make-safe actions and areas to avoid, falls upon the appropriate emergency response organizations for that jurisdiction, carbon dioxide pipeline operators are also well-positioned to bear some of the burden of informing the public about ongoing pipeline emergencies. The pipeline operator will often have the most complete and up-to-date knowledge on many aspects of the emergency, including the circumstances of the release, ongoing remediation activities, characteristics of the released product and any deleterious constituents, and potentially hazardous areas. Operators' direct notification to the public of some emergency response information can reduce delay in distribution of that information by emergency response personnel. Timely receipt of that information, when properly coordinated with emergency response officials for clear and consistent messaging to the public, can help prevent fatalities and injuries by notifying the public of unsafe areas and health conditions to watch for, among other information.

Notwithstanding the heightened importance of timely distribution of emergency response information to the public in the critical moments following an emergency on a carbon dioxide pipeline, operators are not currently required by part 195 to notify the public directly in the event of an emergency on their pipelines.[232] Therefore, PHMSA now proposes a handful of new requirements to address that regulatory gap. First, PHMSA proposes a new paragraph at § 195.402(c)(17) that would require operators of all onshore carbon dioxide pipelines to perform an annual population density survey and establish a 2-mile emergency planning zone on either side of the centerline of their pipelines. This requirement is similar to (and incorporates by reference the supporting analysis of section III.C.3) a proposal elsewhere in this NPRM to amend requirements at § 195.210 governing mandatory safety considerations when evaluating locations for operators of new onshore carbon dioxide pipelines. Second, PHMSA proposes the addition of a new § 195.402(e)(9) requiring all carbon dioxide pipeline operators to directly communicate with affected entities (including, but not limited to, members of the general public) within the 2-mile emergency planning zone during an emergency on their pipelines. Third, PHMSA also proposes renumbering of the existing subparagraphs (e)(9) and (e)(10) to (e)(10) and (e)(11), respectively, to conform with this additional new subparagraph and maintain the current placement of the renumbered subparagraphs at the end of § 195.402.

At § 195.402(c)(17), PHMSA proposes to require all onshore carbon dioxide pipeline operators to perform an annual population density survey along the pipeline route to establish, and subsequently update, an emergency planning zone. As described in section III.C.3, the emergency planning zone extends 2 miles in either direction from the centerline of the carbon

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[232] In a parallel rulemaking proceeding PHMSA has proposed—consistent with a statutory mandate (see Pub. L. 116-120, "The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020)")—to amend its part 192 regulations to require operators' direct notification of the public in an emergency on a gas pipeline. PHMSA," Proposed Rule: Pipeline Safety: Safety of Gas Distribution Pipelines and Other Pipeline Safety Initiatives," 88 FR 61746 (Sept. 7, 2023) (Gas Distribution NPRM).

dioxide pipeline segment to manage the location-based risks to public safety from emergencies on carbon dioxide pipelines.

Operators of newly constructed, relocated, replaced, otherwise changed, or converted to service onshore carbon dioxide pipelines will be required to perform this population density survey prior to commencing initial operations, as required at § 195.210. While the survey information obtained at § 195.210 will be used to provide an initial notification to members of the public in the emergency planning zone, for post-project operations and notifications of emergencies, this population density survey information will also be used to perform the notifications to the public and emergency responders under the requirements proposed at § 195.402(e)(9). PHMSA expects each operator to update this population density survey information once per calendar year, not to exceed 15 months, which will ensure that the operator has up to date information about the population in the areas their carbon dioxide pipelines operate. The survey (whether initial or recurring) must collect data to include: the number of affected entities (including residents and occupants), their ages, preferred language, primary and secondary phone numbers, any specific evacuation information such as special access routes into buildings, and if additional help in evacuation is required.

At § 195.402(e)(9), PHMSA proposes to require all onshore carbon dioxide pipeline operators to notify all affected entities (including, but not limited to, the general public) in the vicinity of the pipeline as soon as practicable during an emergency on a carbon dioxide pipeline. Affected entities include residents, occupants, schools, hospitals, businesses, and other similar institutions. All notifications would be in consultation with the applicable Federal, State, regional, county, local, and tribal emergency response officials, to ensure clear and consistent messaging to the affected public and minimize confusion. PHMSA proposes to require that these communications must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area. For the purposes of this requirement, "as soon as practicable" is taken to mean lower in priority than notifications to PSAPs and emergency response organizations, in accordance with § 195.402(e)(7), and the National Response Center, in accordance with § 195.52, which would continue to allow response agencies quick access to information crucial for public safety. However, these proposed notifications from the onshore carbon dioxide pipeline operator to the affected entities would still be required to be prompt and timely, such that the information provided is useful to the affected entities for accident awareness and the interest of public safety. Affected entities would be taken to mean all members of the public who work or reside in the 2-mile emergency planning zone on either side of the pipeline, as well as any municipalities, school districts, or businesses in those same area(s). To the extent that circumstances require operators to prioritize making those notifications to some entities before others, PHMSA would encourage operators to consider those entities within the area(s) that vapor dispersion analysis (required by this NPRM's proposed § 195.456) indicates could be affected during a pipeline release.

Further, PHMSA expects operator communications under the new requirement for the initial notification must "[indicate] that an emergency exists and what safety precautions members of the public should take" and that subsequent additional messages to the public must be transmitted "as critical safety information is updated, or the emergency is resolved". PHMSA recommends onshore carbon dioxide pipeline operators provide the affected entities (including residents and businesses) with the following information, as it becomes available, in their notifications, including: (1) the operator's response efforts; (2) the magnitude of the emergency and its expected impact; (3) the location(s) of the emergency and any hazardous area(s) to avoid; (4) the specific hazard(s) and the potential risks; (5) safety actions to be taken; and (6) the operator point of contact (i.e., an automated call line or website address) for further information. The proposed § 195.402(e)(9) would be largely consistent with those proposed for part 192-regulated gas distribution operators in PHMSA's Gas Distribution NPRM.

PHMSA expects the proposed amendments to add new paragraphs § 195.402(c)(17) and (e)(9) discussed above would be reasonable, technically feasible, cost-effective, and practicable enhancements of existing PSR requirements for all onshore carbon dioxide pipeline operators. PHMSA's proposed new subparagraph (c)(17) builds on the initial population density survey and emergency planning zone information collection requirements at proposed § 195.210(c) by extending those requirements to all carbon dioxide pipelines on a recurring (annual) basis. As explained in section III.C.3 above, PHMSA has drawn those information collection requirements narrowly by limiting them to the geographic areas most likely to be affected by a pipeline emergency and the information most critical for the protection of the public in those areas; that proposal may also complement existing operator obligations under their IM programs (per § 195.452) and public awareness efforts (per § 195.440). PHMSA further submits that operators' updating that population density survey information annually will (after the initial survey) likely only require minimal additional burden, as that information need only be re-confirmed and supplemented. Additionally, the proposed new subparagraph (e)(9) for operators to directly notify affected members of the public would align with recommendations within industry guidance for actions by carbon dioxide pipeline operators during an emergency as well as voluntary commitments made by recent greenfield carbon dioxide pipeline projects[233]—demonstrating that the direct public notifications proposed in this NPRM are the sort that reasonably prudent operators of carbon dioxide pipelines would undertake in ordinary course given the potential hazards to public safety and the environment from releases from their pipelines. PHMSA's proposed language at the new subparagraph (e)(9) also closely resembles language PHMSA has proposed in the Gas Distribution NPRM rulemaking implementing a Congressional mandate in the PIPES Act of 2020 for direct public notification during emergencies on certain part 192-regulated gas pipelines. Also, should an operator identify a compelling need for regulatory flexibility, the PSR provides for special permit procedures at § 190.341 to request a deviation from specific regulatory requirements.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 believes that operator compliance timelines (one year after the publication date, which would necessarily be in addition to the time since issuance of this NPRM) would provide operators ample time to implement requisite changes and manage any related compliance costs and implementation challenges.

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[233] See, e.g., "Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document; Guidelines for Preparedness and Initial Response to a Pipeline Release of Carbon Dioxide (CO_2)", API, Liquid Energy Pipeline Association, and National Association of State Fire Marshals; (August 2023) pp. 16; Navigator, IL Commerce Comm. Doc. No. 22-0497, "Prepared Direct Testimony of Stephen Lee in re Application for Certificate of Authority to Construct the Navigator Heartland Greenway Project in Illinois" at 12 (Sept. 9, 2022); Summit Carbon Solutions, IA Utilities Board, Doc. No. HLP-2021-0001, "Rebuttal Testimony of Rod Dillon in re Summit Carbon Solutions LLC" at 8 (Aug. 21, 2023).

G. Supplemental Integrity Management and Corrosion Control Measures—§§ 195.452, 195.456, 195.579, Appendix B to Part 195, and Appendix C to Part 195

1. Vapor Dispersion Analysis—§ 195.456

In 2000, RSPA issued IM regulations at §§ 195.450 and 195.452 requiring operators of hazardous liquid and carbon dioxide pipelines to identify all pipeline segments that could affect an HCA and perform additional inspections and assessments on those pipeline segments to address the threats applicable to each.[234] RSPA established the definition of an HCA and provided guidance at Appendix C to Part 195 (as further elaborated in periodically-updated FAQs) with information an operator may use to identify an HCA and factors the operator can use to consider the potential impacts of a release on an area.

Operators are required at § 195.452 to identify which pipeline segments, in the event of a release, could affect an HCA, including using (as appropriate) the factors listed at Appendix C to Part 195 section I.B when complying with § 195.452(f)(1). Among the non-exhaustive list of factors in Appendix C to Part 195 which operators should consider in their process to identify pipeline segments that could affect an HCA are the following: terrain surrounding the pipeline; ditches that could carry spilled product; the nature and characteristics of the product the pipeline is transporting; operating conditions of the pipeline (pressure, flow rate, etc.); hydraulic gradient of the pipeline; pipeline diameter; potential release volume; distance between isolation points; and the potential physical pathways between the pipeline and the HCA. Section I.B. of Appendix

[234] 65 FR 75377: Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline)

C to Part 195 also underscores regulatory requirements at § 195.452(f)(1)-(3) and (g) which establish the operator's responsibility to: (a) have a process for identifying all pipeline segments that could affect an HCA during a release from the pipeline; (b) periodically evaluate its pipeline segments to integrate "all available information" to identify changes that may have occurred in connection with a pipeline (besides the data updated by NPMS concerning high-population areas, other populated areas, unusually sensitive areas, or commercially navigable waterways); and (c) keep its IM program current with this information. Consistent with lessons learned from inspections and PHMSA and State pipeline safety regulatory authorities' oversight of operators' implementation of IM requirements, PHMSA guidance[235] notes that successful operator processes for determining whether their pipelines could affect HCAs must be founded upon sound engineering judgment, with a reasonable amount of conservatism to account for uncertainties in the assumptions and calculation methods used. Pursuant to § 195.452(k)(1), operators must justify and document the assumptions used when making those determinations.

Consistent with the regulatory expectation that operators will employ reasonable conservatism in their IM programs, PHMSA guidance elaborating on IM program requirements at § 195.452(f)(1) encourages operators of all hazardous liquid pipelines (including HVL pipelines) and carbon dioxide pipelines to perform an analysis of the physical pathways and dispersion mechanisms by which the commodity can be transported when identifying pipeline segments that could affect HCAs from a pipeline release. PHMSA guidance at section I.B(5) of Appendix C to Part 195 also instructs pipeline operators transporting any commodity whose

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[235] PHMSA Hazardous Liquid Integrity Management FAQs, FAQ 3.4 and 3.5.

characteristics involve airborne transportation following a release to perform vapor dispersion analyses considering flammability, toxicity, and asphyxiation hazards when determining whether a release from a pipeline segment could affect an HCA.[236] PHMSA also understands from its own and State inspection activity that, in complying with § 195.452(f)(1) and its implementing guidance, many operators may favor performing detailed analyses, such as vapor dispersion, overland spread, or other commodity transportation or dispersion analyses. That said, the performance-based requirement at § 195.452(f)(1) for operators to have a process for identifying which pipeline segments could affect an HCA could be broadly interpreted by operators to apply one or more conservative "safe distance" values within their IM programs to identify whether their pipeline segments could affect an HCA, in lieu of performing periodic detailed analyses (based on their own operational experience, conclusions drawn from results of integrity assessments, other maintenance, surveillance data, and evaluation of consequences of a failure on the HCA). Operators taking this alternative approach must justify how this distance was determined and provide conclusive evidence that this "safe distance" is bounding for its pipeline system.

The above part 195 IM requirements and their implementing guidance provide for performance-based standards allowing operators the flexibility (notwithstanding some prescriptive requirements establishing minimum expectations when critical for safety and the effectiveness of operator IM programs) when developing and implementing their own IM programs and innovative compliance strategies reflecting sound, documented engineering

[236] See FAQ 3.4; Appendix C to Part 195, section I.B(5).

judgment and reasonable conservatism.[237, 238] PHMSA regulations for that reason do not contain an explicit requirement for operators to perform overland spread analyses in determining whether their hazardous liquid or carbon dioxide pipelines could affect an HCA. Similarly, PHMSA regulations contain neither an explicit requirement that operators update the modeling software used in their vapor dispersion analyses to reflect vendor software updates, nor a requirement for particular concentration or exposure levels when modeling hazards within those analyses. PHMSA regulations also do not prescribe any particular "safe distance" values when operators opt to employ that alternative approach when determining whether a pipeline segment could affect an HCA.

However, in the years since the implementation of IM in part 195, PHMSA has observed during its and State pipeline safety regulators partners' inspection and oversight activity that not all operators of pipelines transporting HVLs or carbon dioxide employ the documented, sound engineering judgment and reasonable conservatisms outlined in PHMSA's IM regulations and implementation guidance. By way of example, in the 2020 Satartia accident, the operator performed a vapor dispersion analysis to determine whether its carbon dioxide pipeline could affect HCAs. However, that analysis employed a software model lacking the ability to account for changes in terrain affecting the movement and channeling of the released carbon dioxide vapor (including trees and local topography), such that its results did not predict the possibility of

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[237] PHMSA, Failure Investigation Report, "Denbury Gulf Coast Pipelines, LLC, February 22, 2020" (May 26, 2022). https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf

[238] PHMSA's use of performance-based language in this NPRM is consistent with the Administration's policy of using performance-based standards. See E.O. 12866, Section 1(b), "The Principles of Regulation," (September 30, 1993).

released carbon dioxide to affect HCAs (namely, the nearby village of Satartia).[239] In addition to that modeling limitation, the operator chose assumptions when performing its vapor dispersion analysis that similarly were inadequately conservative to result in modeling that correlated to the real-world event; this was shown by carbon dioxide concentration readings taken in occupied buildings nearly four hours after the accident which nearly exceeded the operator's chosen exposure limit.[240] The operator similarly did not update its vapor dispersion analysis to reflect updates to that software by its vendor in the years between the initial completion of the analysis in 2011 and the accident in 2020. The operator also did not perform an overland spread analysis before the accident; rather, the operator initiated that analysis after the accident and completed it a year later.[241] As a result, the operator failed to identify that pipeline segments nearest to Satartia could affect the village.

The Satartia accident underscores the value of supplementing the existing, flexible IM framework for HVL pipelines (including carbon dioxide pipelines) with targeted, prescriptive standards to supplement operators' choice of documented, reasonably conservative, sound engineering assumptions and methodologies. PHMSA therefore proposes to add a new § 195.456 prescribing the requirements for vapor dispersion analyses when identifying the pipeline segments that could affect an HCA. Operators of pipeline segments transporting an HVL,

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[239] PHMSA, Failure Investigation Report, "Denbury Gulf Coast Pipelines, LLC, February 22, 2020" (May 26, 2022). https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2022-05/Failure%20Investigation%20Report%20-%20Denbury%20Gulf%20Coast%20Pipeline.pdf
[240] PHMSA, Failure Investigation Report, "Denbury Gulf Coast Pipelines, LLC, February 22, 2020" (May 26, 2022)
[241] CPF 4-2022-017-NOPV, Request for Settlement Conference and Hearing (July 25, 2022), https://primis.phmsa.dot.gov/comm/reports/enforce/documents/42022017NOPV/42022017NOPV_Operator%20Response%20to%20Notice%20and%20Request%20for%20Hearing%20and%20Statement%20of%20Issues_07252022_(20-176125)_.pdf

including carbon dioxide, will be directed to this section from § 195.452(f)(1), which requires them to have, as an element in their IM program, a process for identifying which pipeline segments could affect an HCA. The proposed changes further specify that operators of pipelines transporting HVLs (including carbon dioxide) will be explicitly required to supplement their current process with a vapor dispersion analysis, as prescribed at the new § 195.456. The proposed changes at § 195.452(f)(1) and the new § 195.456 supplement the current expectations and guidance from PHMSA that the operator's process for identifying pipeline segments that could affect an HCA must include estimating the severity of potential releases in terms of: volume of the commodity that could be released; the physical pathways and dispersion mechanisms by which the commodity could be transported to an HCA; the amount of commodity that might actually reach the boundaries of the HCA; and the population and environmental resources that could be affected by such a release. The proposed changes further specify that operators of pipelines transporting HVLs (including carbon dioxide) will be explicitly required to supplement their current process with a vapor dispersion analysis, as prescribed at the new § 195.456. Alternatively, when identifying which pipeline segments could affect HCAs, PHMSA proposes at a new § 195.456(a) that operators of pipelines transporting HVLs could use a default 2-mile distance on each side of the centerline to identify intersections with HCAs. Finally, proposed § 195.456 (d) includes a requirement for all HVL pipeline operators (including carbon dioxide pipeline operators) to make and maintain records of vapor dispersion analyses, reviews, and updates performed under this section, according to the IM program recordkeeping requirements at § 195.452(l).

At the new § 195.456, PHMSA proposes that operators of HVL pipelines (including carbon dioxide pipelines) must use a validated, engineering-based vapor dispersion analysis and must include in that analysis each of the following elements to determine the distance a release could affect an HCA on each pipeline segment: (1) physical and thermodynamic properties and characteristics of the product the pipeline is transporting and operating conditions of the pipeline, including but not limited to pressure, temperature, flow rate, hydraulic gradient of the pipeline, density, and vapor pressure; (2) diameter of the pipeline, potential release volume, and distance between isolation points; (3) release characteristics, including release rates (instantaneous or continuous), orientation of the release, and phase composition of the release; (4) concentrations of released product, in terms of flammability, asphyxiation, and toxicity, at which the operator determines the pipeline segment could affect an HCA; (5) terrain surrounding the pipeline, including natural topography (e.g., valleys, ravines, and hills) and manmade structures (e.g., buildings, roadways, ditches, and canals); (6) vegetation in any area that could interact with released vapor; and (7) typical weather conditions that could affect released vapor, including, but not limited to, humidity, prevailing winds, and temperature. The factors described above are consistent with the factors currently listed within guidance at section I.B of Appendix C to Part 195. Not all the above factors may apply to all HVL pipeline segments; PHMSA proposes to require operators include each factor in their analysis to the full extent that it is applicable, and document the analysis and decisions made supporting that analysis, in accordance with IM recordkeeping requirements at § 195.452(l). Operators of HVL pipelines (including carbon dioxide pipelines) would be required to use sound engineering judgment, with a reasonable amount of conservatism, to account for uncertainties and limitations in the assumptions and calculation methods used in their vapor dispersion analyses. Operators must justify and document their analyses (including a description of the applicable calculation methods and identification of any material assumptions used) when making these determinations. PHMSA further expects that operators will use only vapor dispersion software models which have been validated against experimental or real-world observed data within their vapor dispersion analyses to ensure the accuracy of modeling results.

There are commercial solutions for implementing the requirement for operators to have a process for identifying which pipeline segments could affect an HCA, including overland spread analysis and vapor dispersion modeling. Each of those solutions may have its own benefits and disadvantages in terms of modeling detail, considered variables and factors, and resulting computation time. PHMSA does not endorse any particular solution or model and expects operators to choose and document a modeling approach that is appropriate for the operating and physical conditions associated with their pipeline and transported product and which represents a reasonably conservative approach for identifying HCAs. In some cases, this might entail the use of multiple models or analyses, depending on factors such as transported product, terrain, and environmental and atmospheric conditions. In other cases, an operator might choose to use a combination of: (1) an initial simpler and less time-intensive modeling approach along the entire pipeline segment as an initial screening tool, used alongside conservative assumptions or buffers with respect to the factors proposed at § 195.456; and (2) subsequent detailed modeling for particular areas of concern identified by the initial modeling results.[242] These proposed requirements are consistent with the approaches recommended in relevant industry guidance.[243]

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[242] ADMLC Webinar (Dense gas dispersion modelling in complex terrain, with a focus on carbon dioxide pipelines) https://admlc.files.wordpress.com/2023/03/admlc-webinar_-dense-gas-dispersion-modelling-in-complex-terrain-with-a-focus-on-carbon-dioxide-pipelines-20230307_140132-meeting-recording-1.mp4

[243] DNV-RP-F104. Edition February 2021, "Design and operation of carbon dioxide pipelines," amended September 2021. "In many assessments, empirical integral models should provide acceptable modelling capability, but in areas

Many software models used in vapor dispersion analyses are continually updated to more accurately model theoretical releases and better fit those theoretical releases to experimental and observed real-world releases. Developers of some models have also been involved in large-scale experimental releases of carbon dioxide and have used the data to modify their modeling algorithms.[244] Consistent with the existing requirement at § 195.452 to ensure that operators have identified all HCAs, PHMSA now proposes at § 195.456(c) an explicit requirement for operators to update their vapor dispersion analyses periodically to reflect vendor's updates to the software models employed. These software updates would be required to be performed and documented every 15 months, but no less than once each calendar year. Similarly, PHMSA proposes that an operator should also update its analysis to reflect material changes to any of the factors identified at the proposed § 195.456(b) on the same schedule. Taken together, these proposed requirements would ensure that an HVL pipeline operator's identification of its pipeline segments that could affect an HCA are accurate and current, reflecting the best science and knowledge. This schedule is consistent with requirements elsewhere in part 195 for operators to review their manuals of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies (see § 195.402(a)). When performing their annual reviews of their vapor dispersion models, operators would need to evaluate and document any material

where the combined effects of topography, buildings, pits, etc. and the heavy gas properties of the released CO_2 may have a significant effect on the exposure of people or livestock, more detailed simulations using advanced dispersion tools (e.g. computational fluid dynamics (CFD)) should be considered."

[244] Sherpa Consulting Pty Ltd, "Dispersion Modelling Techniques for Carbon Dioxide Pipelines in Australia," (June 23, 2015) pp. 129.

changes made to the software model itself or any factor(s) considered in their analysis required by § 195.452(b)(1).

PHMSA acknowledges that the resources required to perform vapor dispersion analyses pursuant to the proposed new § 195.456 may not be practicable for all HVL operators or pipeline segments. PHMSA therefore proposes that operators could, in lieu of performing pipeline-specific vapor dispersion analyses, opt to use an alternative distance of 2 miles on either side of their pipeline segments as the basis for determining if a pipeline segment could affect an HCA. PHMSA selected this 2-mile distance for the same reasons (discussed in sections III.C.3 and III.F.3) it selected a 2-mile distance for the emergency planning zone pursuant to the proposed §§ 195.210, 195.402(c)(17), and 195.402(e)(9). Also, a 2-mile distance is consistent with results of computational modeling of unusually sensitive areas (as that term is defined at § 195.6) in connection with all part 195-regulated pipelines.[245] Further, a single, uniform, default distance (for carbon dioxide and other HVLs alike) would facilitate improved regulatory oversight activity by PHMSA and State pipeline safety regulatory authorities.

PHMSA expects the proposed amendments regarding vapor dispersion analysis requirements described above would be reasonable, technically feasible, cost-effective, and practicable for HVL (including carbon dioxide) pipeline operators. Industry guidance and technical documentation emphasize the importance of performing vapor dispersion analyses when evaluating the risks to public safety and the environment from carbon dioxide pipelines in particular; unsurprisingly, some operators of planned greenfield carbon dioxide pipelines have

[245] "Pipeline Safety: Areas Unusually Sensitive to Environmental Damage", 65 FR 80534 (Dec. 21, 2000)

committed to performing such analyses and (regardless of the results of those analyses) bringing the entirety of their pipeline under their IM programs in light of the risks to public safety and the environment from releases of carbon dioxide.[246] And, as noted above, PHMSA understands that some HVL pipeline operators—consistent with longstanding PHMSA implementing guidance for IM programs—already perform vapor dispersion analyses when complying with their § 195.452(f)(1) could affect HCA analyses; the NPRM's proposed revisions at that provision would codify that practice while allowing operators freedom to choose from among existing (and any future) vapor dispersion analysis modeling software. Similarly, PHMSA has narrowly drawn the mandatory elements of vapor dispersion analyses proposed at § 195.456 to maximize operator flexibility; those elements track those factors within current IM program guidance at Appendix C to Part 195 as well as considerations identified in pertinent industry guidance.[247] Also, the proposed timeline of an annual review and update of vapor dispersion modeling is a common-sense approach to ensure that such analyses remain as accurate inputs to an operator's performance-based IM program; those reviews and updates could (as noted above) be integrated within other, related programmatic reviews performed by operators in compliance with other sections of part 195. Lastly, operators for whom those vapor dispersion analysis requirements would be impractical would have the option to use by way of substitute in their could affect HCA analysis a conservative, 2-mile distance on either side of their pipeline that would be

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[246] See, e.g., "Carbon Dioxide (CO_2) Emergency Response Tactical Guidance Document; Guidelines for Preparedness and Initial Response to a Pipeline Release of Carbon Dioxide (CO_2)", API, Liquid Energy Pipeline Association, and National Association of State Fire Marshals; (August 2023) pp. 10-12; Det Norske Veritas, "DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines," at pp. 25, 33-34 (Sept. 2021).
[247] See Det Norske Veritas, "DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines," at pp. 33 (Sept. 2021).

consistent with the emergency planning zone proposed elsewhere in this NPRM (discussed in sections III.C.3 and III.F. above). Further, the PSR also provides for special permit procedures at § 190.341 to request a deviation from §§ 195.452 and 195.456.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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. PHMSA also believes that operator compliance timelines—based on an effective date of the proposed requirements of one year after the publication date of a final rule in this proceeding, which timeline would necessarily be in addition to the time since issuance of this NPRM)—would provide HVL pipeline operators (including carbon dioxide pipeline operators) ample time to implement requisite changes and manage any related compliance costs.

2. Expanded Internal Corrosion Control—§ 195.579

Section 195.579 requires operators of pipelines that transport hazardous liquid or carbon dioxide that would corrode the pipeline, to investigate the corrosive effect of the transported product on the pipeline and take adequate steps to mitigate internal corrosion. In performing that mitigation, § 195.579 also prescribes requirements for the use of corrosion inhibitors. Further, § 195.579 requires operators to inspect the internal surface of the pipe for evidence of corrosion whenever pipe is removed from a pipeline. This provision also includes a requirement to investigate circumferentially and longitudinally beyond the removed pipe to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe. Finally, § 195.579 requires operators of aboveground breakout tanks to install a tank bottom lining in accordance with API RP 652 unless the operator identifies that such a lining is not necessary for the tank.

Section 195.579 provides operators flexibility in determining how to meet the performance requirement to "mitigate internal corrosion." PHMSA does not have record of any reportable accident caused by internal corrosion involving a pipeline transporting carbon dioxide and commends the industry for that aspect of their safety record.[248,249] However, PHMSA understands that historical success may be a function of the limited existing carbon dioxide infrastructure (capture, storage, and transportation) and end uses (mostly EOR applications), which generally transports carbon dioxide containing relatively few impurities when compared to potential carbon dioxide streams associated with new, diverse potential sources and end uses.[250] As explained in section II.B, future potential sources of carbon dioxide, specifically those that will be relied upon to meet climate change mitigation goals (e.g., captured flue gas from gas processing plants, ethanol production plants, and coal- or natural gas- fired power plants) contain a higher number and quantity of impurities. There is not yet a consensus specification or standard for the quality and purity of carbon dioxide being transported; nor is any likely to emerge soon, given that impurities in a carbon dioxide stream will depend on a number of variables, including the fuel type, the energy conversion process (post-combustion,

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[248] *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data*

[249] "Internal corrosion in dense phase CO_2 transport pipelines - state of the art and the need for further R&D", Dugstad et al, 2012, "More than 5000 km of carbon steel pipelines carrying liquid CO_2 have been or are in operation internationally, most of these in the USA. The CO_2 has been dry and no corrosion problems have been reported in the part of the system that has been exposed to dry CO_2 only. Corrosion has been reported at the injection point and in the process system when free water is present."

[250] Peletiri P.S., Rahmanian N., Mujtaba I.M., 2017, Effects of impurities on CO_2 pipeline performance, Chemical Engineering Transactions, 57, 355-360 DOI: 10.3303/CET1757060 at pp. 1-2

pre-combustion, or oxyfuel), the capture process, and the final use or storage location.[251] As new carbon capture technologies emerge, novel chemical impurities may emerge as well, with an unknown effect on corrosion.[252] Among the impurities in a commodity stream posing the greatest risk of corrosion are those known to reduce the solubility of water in streams of carbon dioxide transported by pipelines. PHMSA expects that more types and quantities of such impurities may be transported in carbon dioxide product streams. To the extent that increased interest in carbon dioxide transportation results in more supercritical-phase carbon dioxide pipelines, operators may find themselves transporting carbon dioxide in a two-phase flow consisting of a mixture of both liquid-phase carbon dioxide and supercritical-phase carbon dioxide. The liquid-phase carbon dioxide increases the possibility of an aqueous liquid within the commodity stream to precipitate out and cause internal corrosion. This is because depressurization of supercritical-phase carbon dioxide can occur during normal operations, abnormal operations, and emergencies (including accidental releases and failures of product containment when the carbon dioxide stream experiences a rapid change from a state of high pressure to one of lower pressure). During depressurization, the lower pressure inside the pipeline contributes to the formation of two-phase flow, which drives impurities to the phase where their solubility is the highest (either in the liquid carbon dioxide or into a separate aqueous phase). Internal corrosion of carbon dioxide pipelines may also be caused by microbiologically

[251] "Internal corrosion in dense phase CO_2 transport pipelines - state of the art and the need for further R&D", Dugstad et al, 2012.
[252] "Dense Phase CO_2 Corrosion and the Impact of Depressurization and Accumulation of Impurities," Dugstad et al, 2013 at pp. 2.

influenced corrosion. This type of internal corrosion has been observed in pipelines transporting carbon dioxide saturated with water and has resulted in leaks in those systems.[253]

Considering the real potential that pipeline operators will be transporting carbon dioxide from a variety of different sources and containing various types and quantities of impurities that could cause internal corrosion, PHMSA proposes a new § 195.579(e) to require all operators of pipelines transporting carbon dioxide to develop and implement a monitoring and mitigation program to manage the corrosive effects of the constituents in the carbon dioxide product stream. This new proposed requirement identifies specific, commonly understood potential corrosion-affecting constituents that operators establishing such programs would be required to monitor and mitigate, including, but not limited to microbes, water, oxygen, methane, hydrogen sulfide, carbon monoxide, sulfur oxides, and nitrogen oxides. Regarding the timeframe to implement this new monitoring and mitigation program for existing pipelines currently regulated under part 195, those pipelines transporting a fluid consisting of greater than 90 percent carbon dioxide molecules compressed to a supercritical state which were constructed or converted before the effective date of a subsequent final rule would have up to 12 months after the effective date to comply with the requirements of this paragraph. All other pipelines transporting carbon dioxide that would become regulated under part 195 per the proposals in this NPRM would be expected to comply with the requirements of this paragraph on the effective date of a final rule in this proceeding.

[253] "MIC in a CO_2 Gathering Line? A Field Case Study of Microbiologically Influenced Corrosion", Hinkson et al, 2013

PHMSA also proposes that carbon dioxide pipelines would be required to choose from technology used to mitigate the corrosion-affecting constituents, including product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects of constituents in a carbon dioxide product stream. More specifically, PHMSA proposes that the technology to mitigate corrosion-effecting constituents be capable of allowing no free water and otherwise limit water to 50 ppm by volume in any phase. This specification for water content would enable a pipeline to transport sufficiently dry carbon dioxide to mitigate, or otherwise make negligible, the influence of other impurities that often accelerate the mechanisms of internal corrosion.[254] PHMSA recognizes that this water content specification is more stringent than specifications provided in relevant literature and used by current carbon dioxide pipeline operators; however, given that no consensus has been reached on an acceptable, industry-wide water content specification for carbon dioxide pipeline transportation, PHMSA proposes the more conservative specification stated above.[255,256] PHMSA welcomes comments from industry and other interested parties in support of or against

[254] "Internal corrosion in dense phase CO_2 transport pipelines - state of the art and the need for further R&D", Dugstad et al, 2012, "It seems to be generally accepted that the corrosion rate is insignificant when the water content is well below the solubility limit.", and "Field experience and most laboratory experiments show that dry pure CO_2 and pure CO_2 that contains dissolved water well below the saturation limit in the pure CO_2-H_2O system is non-corrosive to carbon steel under transportation pipeline conditions. […] At present, there is a lack of data and therefore it is not possible to define the limits for the various impurities when they are mixed."
[255] Pipeline Research Council International, Inc. (PRCI), "Pipeline Transportation of CO_2 SOTA, Gap Analysis and Future Project Roadmap" (Oct. 13, 2023).
[256] "Internal corrosion in dense phase CO_2 transport pipelines - state of the art and the need for further R&D", Dugstad et al, 2012, "There is however no consensus on what the actual target for the maximum water concentration should be. It has been argued that full dehydration down to 50 ppmv should be applied. This limit has been specific for the first CO_2 pipelines in the USA[256] and for the Snøhvit pipeline in Norway."

this proposal, provided that such comments and positions are supported with pipeline inspection and economic data.

PHMSA proposes that the technology to mitigate corrosion-effecting constituents be capable of limiting hydrogen sulfide to 20 ppm by volume of total product in any phase. PHMSA has seen support in relevant literature for a range of allowable hydrogen sulfide concentrations, with some limits as low as 20 ppm; these limits also have the benefit of greatly reducing the possibility of sour cracking. [257,258,259] With regard to the safety of the public and the environment, OSHA and NIOSH have established that IDLH level of hydrogen sulfide is 100 ppm, and PHMSA proposes to incorporate that limit, with a factor of safety, in the product quality specification of this section related to impurities or other constituents that are often transported along with carbon dioxide in a carbon dioxide product stream.[260] Therefore, PHMSA proposes a limit to the concentration of hydrogen sulfide that can be transported in a carbon dioxide stream as a measure to protect the public and the environment.[261]

PHMSA proposes that operators include a process to evaluate whether corrosion-affecting constituents are effectively monitored and mitigated by their monitoring and mitigation programs at least four times per calendar year, at intervals not to exceed 4 ½ months. Additionally, PHMSA proposes operators evaluate and review their monitoring and mitigation

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[257] Pipeline Research Council International, Inc. (PRCI), "Pipeline Transportation of CO_2 SOTA, Gap Analysis and Future Project Roadmap" (Oct. 13, 2023).
[258] "Internal corrosion in dense phase CO_2 transport pipelines - state of the art and the need for further R&D", Dugstad et al, 2012.
[259] Race, J. M., Wetenhall, B., Seevam, P. N., & Downie, M. J. (2012). Towards a CO_2 Pipeline Specification: Defining Tolerance Limits for Impurities. The Journal of Pipeline Engineering, 11(3): 173-190
[260] OSHA: https://www.osha.gov/chemicaldata/652 ; NIOSH: https://www.cdc.gov/niosh/idlh/7783064.html
[261] Race, J. M., Wetenhall, B., Seevam, P. N., & Downie, M. J. (2012). Towards a CO_2 Pipeline Specification: Defining Tolerance Limits for Impurities. The Journal of Pipeline Engineering, 11(3): 173-190

programs (basing these evaluations and reviews on the results of the program) at least once each calendar year, at intervals not to exceed 15 months. Based on the evaluation and review of the results of the programs, operators would then update their monitoring and mitigation programs and implement adjustments, as necessary.

Above, PHMSA has proposed minimum Federal standards for acceptable concentrations of water and hydrogen sulfide in carbon dioxide product streams. PHMSA reminds operators of all pipelines (including carbon dioxide pipelines) of the requirements at § 195.452 for an operator to analyze and integrate all available information about the integrity of the entire pipeline and the consequences of a possible failure along the pipeline. Carbon dioxide pipelines may transport varying combinations and concentrations of corrosion-affecting constituents. These corrosion-affecting constituents can cause cracking, such as stress corrosion cracking, sulfide stress corrosion cracking, or hydrogen induced cracking. The presence of these constituents might not only affect pipeline segments that are in or could affect HCAs, but the entire pipeline. Operators can analyze and integrate the information obtained from the monitoring and mitigation program proposed at § 195.579(e) as part of their IM program to mitigate the corrosive effects of the combined constituents in the carbon dioxide product stream and prevent pipeline failures that might occur by transporting corrosion-affecting constituents in a carbon dioxide product stream.

Finally, PHMSA proposes to revise the title of § 195.579 to refer to the section content without doing so in the form of a question and replace the references to "you" with "each operator" or similar language, where appropriate.

PHMSA expects the proposed amendments to internal control corrosion requirements at § 195.579 would be reasonable, technically feasible, cost-effective, and practicable for operators of hazardous liquid and carbon dioxide pipelines. PHMSA's proposed changes to the existing language at § 195.579(a)-(d) are merely clerical revisions that do not change the substantive obligation of operators of all hazardous liquid and carbon dioxide pipelines to manage internal corrosion of their pipelines. PHMSA's proposed addition of a new subparagraph (e) elaborates on those longstanding requirements (as well as complementary material compatibility requirements at § 195.4) by specifying minimum expectations for carbon dioxide pipeline operators' compliance efforts. Within the proposed guardrails at subparagraph (e), carbon dioxide pipeline operators (who are best positioned to understand which corrosion-affecting constituents are in their pipelines' product streams and to control operating parameters that could influence their corrosion potential) would have flexibility to design and implement monitoring and mitigation programs based on the needs of their pipelines. For those carbon dioxide pipeline segments which could affect an HCA, some of those mandatory elements may reinforce (or be integrated within) the operator's compliance efforts with respect to existing and proposed (see section III.G.3 below) IM program requirements. Additionally, PHMSA has narrowly drawn its proposed new subparagraph (e) requirements to be consistent with industry standards and technical guidance for carbon dioxide pipelines emphasizing the importance of internal corrosion control management (including periodic and continuous monitoring) of those constituents listed at § 195.579(e) across the diverse potential product stream compositions and operating parameters.[262] PHMSA has observed that several recent carbon dioxide pipeline greenfield

[262] Det Norske Veritas (DNV), DNV-RP-F104, Design and Operation of Carbon Dioxide Pipelines at 37, 49-50 (Sept. 2021); NARUC, Onshore U.S. Carbon Pipeline Deployment: Siting, Safety, and Regulation at pp. 14 (June 2023); PRCI, Pipeline Transportation of CO_2 SOTA, Gap Analysis and Future Project Roadmap at pp. 1, 16, 20 (Nov. 2023).

projects have voluntarily committed to adopting the sort of measures (including continuous internal corrosion control monitoring at the receipt point) proposed in this NPRM,[263] demonstrating that these measures are the sort that reasonably prudent operators of carbon dioxide pipelines would undertake in ordinary course given the potential lost commercial value and hazards to public safety and the environment from releases from their pipeline projects. Also, should an operator identify a compelling need for regulatory flexibility, the PSR provides for special permit procedures at § 190.341 to request a deviation from specific regulatory requirements.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 believes that operator compliance timelines (two years after the publication date of a final rule in this proceeding for existing carbon dioxide pipelines, and one year after the publication date for new carbon dioxide pipelines—both of which would necessarily be in addition to the time since issuance of this NPRM) would provide operators ample time to implement requisite changes and manage any related compliance costs and implementation challenges.

3. Enhanced Integrity Management—§ 195.452, Appendix B to Part 195, and

[263] See, e.g., Navigator, IL Commerce Comm. Doc. No. 22-0497, "Prepared Direct Testimony of Vidal Rosa in re Application for Certificate of Authority to Construct the Navigator Heartland Greenway Project in Illinois" at 6 (Sept. 9, 2022); Wolf Carbon Solutions, IL Commerce Comm. Doc. No. 23-0475, "Mt. Simon Hub Pipeline System Application for Certificate of Authority" at pp. 30 (June 16, 2023).

Appendix C to Part 195

Section 195.452 contains the requirements for an IM program for both hazardous liquid and carbon dioxide operators and is applicable to each pipeline segment that could affect an HCA.

Paragraph (e) lists the minimum factors that an operator must consider when establishing an integrity assessment schedule. These factors include previous assessment results, geohazards, operating stress of the pipeline, leak history, and product transported, among others. Paragraph (e) also notes that Appendix C to Part 195 provides additional guidance to operators on risk factors.

Paragraph (f) requires that operators must continually update their IM programs to reflect operating experience, conclusions drawn from assessment results and other data, and evaluations of consequences to the HCA from failures. Paragraph (f) also contains the minimum elements of a written IM program, including a process for identifying which pipeline segments could affect an HCA.

Paragraph (i) requires operators to take measures to prevent and mitigate the consequences of a pipeline failure that could affect an HCA. When identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect HCAs. Subparagraph (i)(2) and its subparagraphs require the operator to consider all relevant risk factors when making this determination, including the surrounding terrain, characteristics of the transported product, and amount of possible released product, among other risk factors.

Subparagraph (i)(4) requires certain operators[264] to determine if an EFRD is needed in the event of a hazardous liquid release in an HCA or an area which could affect an HCA. The Valve Rule[265] modified § 195.452(i)(4) to clarify the requirements for conducting EFRD evaluations for HCAs, particularly when an operator installs EFRDs as preventive and mitigative measures to improve response times for, and mitigate the consequences of, pipeline ruptures. EFRDs that are installed in accordance with § 195.452(i)(4) must meet all rupture-mitigation valve (RMV) requirements in part 195. Section 195.450 defines an EFRD as a check valve or a remote-control valve. Although check valves can be considered as either an automatic-shutoff valve (ASV) or an EFRD in some applications, this NPRM only considers them to be an RMV if an operator can demonstrate the valve's protective equivalence when the valve is used for segment shut-off and isolation in response to a rupture. In the Valve Rule, PHMSA also required that operators conduct and complete risk analyses and assessments prior to placing into service all onshore pipelines with diameters of 6 inches or greater that are constructed or have had 2 or more miles of pipeline replaced within 5 contiguous miles within a 24-month period after April 10, 2023.

Appendix C to Part 195, "Guidance for Implementation of an Integrity Management Program," provides guidance to help operators of hazardous liquid and carbon dioxide pipelines subject to part 195 implement the IM requirements. Section I of Appendix C to Part 195 provides guidance on identifying HCAs and relevant factors when considering a pipeline segment's

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[264] Section 195.452(i)(4) does not apply to any carbon dioxide pipelines; additionally, amendments to that subparagraph introduced in the Valve Rule do not apply to hazardous liquid gathering lines.
[265] 87 FR 20940, "Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards," (April 8, 2022).

potential impact on an HCA. Section III of Appendix C to Part 195 contains safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported. Appendix C to Part 195 can be used by operators of hazardous liquid and carbon dioxide pipelines alike.

Appendix B to Part 195, "Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines," provides guidance on the risk-based alternative to pressure testing older hazardous liquid and carbon dioxide pipelines allowed by § 195.303. While not explicitly referencing PHMSA's IM regulations, Appendix B to Part 195 establishes test priorities based on the risk profile of a given pipeline segment for older pipelines that were not previously pressure tested based on factors that largely overlap with the factors identified in PHMSA's IM regulations and implementing guidance within Appendix C to Part 195.

The first step in the process identified in Appendix B to Part 195 is for the operator to determine the classification based on the type of pipe and the pipeline segment's proximity to populated or environmentally sensitive areas. Secondly, the operator must adjust these classifications based on the pipeline failure history, product transported, and the potential release volume. These adjustments for classification share some similarities with IM risk factors. Table 4 of Appendix B to Part 195, Product Indicators, provides risk classifications based on the product transported. These classifications are based on the degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; volatility; flammability; and water solubility.

The IM regulations are applicable to both carbon dioxide and hazardous liquid pipeline operators, including gathering lines, with few exceptions and have generally been implemented across a broad variety of pipeline systems since their addition to part 195 on December 1, 2000,[266] including on supercritical-phase carbon dioxide pipelines. PHMSA is not proposing significant changes to the IM regulations. However, in the development of this NPRM, PHMSA is proposing four improvements to the IM regulations with respect to carbon dioxide pipelines: (1) deleterious constituents within the transported product streams, (2) risk classification of carbon dioxide in the appendices to part 195, (3) use of EFRDs on carbon dioxide pipelines, and (4) conforming changes for consistency with other proposed sections.

Deleterious constituents

As noted in section II.A, certain constituents of carbon dioxide product streams, including hydrogen sulfide, can present serious public safety and environmental risks themselves. Many constituents in carbon dioxide product streams other than the carbon dioxide commodity itself, such as water, can also increase internal corrosion rates. Additionally, as noted in section II.G.2, with new carbon-capture technologies, new constituents (some of which may be deleterious in nature) can be part of the carbon dioxide product stream when compared to traditional sources.[267] The purity of carbon dioxide product streams from alternative sources, when compared to traditional sources, can also be lower. This can result in higher concentrations of constituents in the transported carbon dioxide product stream that are deleterious to either pipeline integrity (e.g., by inducing internal corrosion) or public safety and the environment (when released to the environment).

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[266] 65 FR 75377, PHMSA, "Pipeline Safety: Pipeline Integrity Management in High Consequence Areas (Hazardous Liquid Operators With 500 or More Miles of Pipeline)," (December 1, 2000).
[267] Race, J. M., Wetenhall, B., Seevam, P. N., & Downie, M. J. (2012). Towards a CO_2 pipeline specification: defining tolerance limits for impurities. The Journal of Pipeline Engineering, 11(3), 173-190.

Many of these deleterious constituents can also be present in hazardous liquid pipelines; most notably, hydrogen sulfide and water are frequently present in small concentrations within crude oil product streams alongside the crude oil commodity itself. Sour crude oil can contain hydrogen sulfide in concentrations up to 1,000 ppm, according to the material safety data sheet for the U.S. Department of Energy's Strategic Petroleum Reserve.[268] As part of an IM program, it is therefore prudent for both carbon dioxide and hazardous liquid pipeline operators to consider the potential for deleterious constituents in their product streams when determining the relative risk that product stream presents. Given the heightened public safety and environmental risks associated with pipelines an operator has determined could affect an HCA in the event of a release, PHMSA is proposing to amend § 195.452(e)(1)(iv) and (i)(2)(iii) to underscore operators' obligation to consider within their IM programs the characteristics of deleterious constituents alongside the characteristics of the commodity transported in the product stream when considering risk factors for scheduling assessments and determining the need for additional preventative and mitigative measures. The modifications at §§ 195.452(e)(1)(iv) and 195.452(i)(2)(iii) would add "deleterious constituents such as hydrogen sulfide and water" alongside preexisting text requiring the operator to consider the product transported as a risk factor.

Carbon dioxide risk classification

Both table 4 of Appendix B to Part 195 and the "Product Transported" table of Appendix C to Part 195 sort products into three risk indicator designations: high, medium, and low. The

[268] Safety Data Sheet - Petroleum Crude Oil (Sour), U.S. Department of Energy, (May 26, 2012). https://www.spr.doe.gov/reports/docs/SDS-Petroleum_Crude_Oil_(Sour)_(2017).pdf.

risk indicator of high for both appendices includes two categories of product characteristics: (a) highly volatile and highly flammable, and (b) highly toxic. The risk indicator of medium for both appendices includes one category of product characteristics: flammable (flashpoint less than 100 °F). The risk indicator of low for Appendix C to Part 195 includes one category of product characteristics: non-flammable (flashpoint greater than 100 °F). Appendix B to Part 195 includes two categories of product characteristics under the risk indicator of low: (a) non-flammable (flashpoint greater than 100 °F), and (b) highly volatile and non-flammable/non-toxic.

These appendices provide examples for each category of product characteristics. Carbon dioxide is listed under "highly volatile and non-flammable/non-toxic" within Appendix B to Part 195. Carbon dioxide is not included in any other category within either table.

When considering the relative risk posed by different products transported under part 195 regulations, operators should consider several key characteristics: volatility, toxicity, flammability, and asphyxiation potential. Carbon dioxide is highly volatile and asphyxiating. PHMSA has determined that these characteristics have a greater safety risk indicator than other non-flammable products, such as diesel, fuel oil, kerosene, and most crude oils, as these products are not asphyxiating in nature. On the other hand, PHMSA has determined that carbon dioxide's characteristics have a lower safety risk indicator than highly toxic products (such as benzene and crude oils which contain a high content of hydrogen sulfide) which could induce death or permanent injury immediately upon or shortly after exposure at a given concentration; although asphyxiating products such as carbon dioxide can entail death or permanent injury, those effects will generally require longer exposure periods and concentrations shorter exposure periods—shorter exposure periods or lower concentrations may result in only temporary effects. Likewise, PHMSA has determined that products that are both highly volatile and highly flammable have a higher safety risk indicator than carbon dioxide, which (although it is highly volatile) is non-flammable. Therefore, PHMSA proposes adding an additional category of products under the medium risk-indicator in both table 4 of Appendix B to Part 195 and the "Product Transported" table in Appendix C to Part 195: asphyxiating. PHMSA proposes adding carbon dioxide as the sole example of a product meeting this category in both tables. In table 4 of Appendix B to Part 195, PHMSA proposes removing the final category under the low-risk indicator (highly volatile and non-flammable/non-toxic), as PHMSA proposes moving carbon dioxide to a new category under the risk indicator of medium, as noted.

Emergency flow restricting devices

The Pipeline Safety Act of 2011 (49 U.S.C. 60102(n)(2)) required the U.S. Governmental Accountability Office (GAO) to conduct a study on the ability of transmission pipeline facility operators to respond to a hazardous liquid or gas release from a pipeline segment located in an HCA. The GAO was required to consider the swiftness of leak detection and pipeline shutdown capabilities, the location of the nearest response personnel, and the costs, risks, and benefits of installing ASVs and RCVs. The resulting study, GAO-13-168,[269] did not include carbon dioxide releases in its scope; however, PHMSA's experience with carbon dioxide pipelines is consistent with the study's findings. The lack of rapid closure capability has been found to have significantly exacerbated both the volume released and the adverse consequences in past accidents, even when emergency situations were quickly recognized by the operator. A report by

[269] GAO-13-168, U.S. Government Accountability Office, "Pipeline Safety: Better Data and Guidance Needed to Improve Pipeline Operator Incident Response," (January 2013). https://www.gao.gov/assets/gao-13-168.pdf.

Oak Ridge National Laboratory (ORNL)[270] confirmed that "swiftness of valve closure has a significant effect on mitigating potential socioeconomic and environmental damage to the human and natural environments." Similarly, the GAO study also found that "quickly isolating the pipeline segment through automated valves can significantly reduce subsequent damage by reducing the amount of hazardous liquid released." These findings are also true for carbon dioxide releases. Furthermore, carbon dioxide rapidly expands upon release, and reducing the amount of carbon dioxide released significantly reduces the risk to the public from asphyxiating vapor clouds, which can migrate significant distances from the original release point (see section II.D).

Therefore, carbon dioxide pipelines should be held to the same standard as hazardous liquids pipelines with regards to EFRD requirements. Therefore, PHMSA proposes modifying § 195.452(i)(4) to require pipeline operators to install an EFRD if an operator determines that an EFRD is needed on a pipeline segment to protect an HCA in the event of a hazardous liquid or carbon dioxide pipeline release. This retains preexisting language and adds "or carbon dioxide" at § 195.452(i)(4).

Fixed vapor detection and alarm systems

In sections III.C.5 and III.D.2, PHMSA proposes a new § 195.263 requiring fixed vapor detection and alarm systems on part 195-regulated pipelines transporting HVLs (including carbon dioxide) which are newly constructed, replaced, relocated, otherwise changed, or converted to service on or after the effective date of a final rule, at all pump stations, compressor

[270] ORNL/TM-2012/411

stations, meter stations, and valve stations, to include launching and receiving facilities. Applicable maintenance and testing requirements for fixed vapor detection and alarm systems are described at § 195.429. PHMSA recognizes and details the unique hazards that HVLs pose to the public and the environment in section III.C.5. PHMSA believes that these risks are not only present on newly constructed, replaced, relocated, otherwise changed, or converted pipelines, but that the risks also apply to existing HVL pipelines—in particular those from whom a release could affect a population center or ecological resource designated as an HCA.[271]

Accordingly, PHMSA proposes at a new § 195.452(i)(5) to require operators of existing pipelines transporting an HVL to have fixed vapor detection and alarm systems meeting the requirements of proposed § 195.263, at each pump station, compressor station, meter station, and valve station (including facilities for launching and receiving ILI tools or instrumented internal inspection devices) that are located in, or which could affect, an HCA. PHMSA proposes a period of 24 months after the effective date of a final rule issued in this rulemaking proceeding for operators to confirm that existing equipment at each pump station, compressor station, meter station, and valve station (including facilities for launching and receiving ILI tools or instrumented internal inspection devices) includes vapor detection and alarm systems meeting the requirements of the proposed § 195.263 or to make the necessary upgrades to comply with this preventive and mitigative measure. A conforming change is also proposed at § 195.452(i)(1) to reflect the addition of this new subparagraph.

Conforming changes

[271] *https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data*

Section 195.450 contains the definitions applicable to hazardous liquid and carbon dioxide pipeline segments that could affect or are in HCAs. The definitions are contained at § 195.450, but have applicability in the IM-related sections, specifically §§ 195.452, 195.454, and the new section proposed in this NPRM, § 195.456, and anywhere else they are referenced in part 195 (i.e., §§ 195.48, 195.260, 195.402 and 195.418.) PHMSA is proposing to amend the language at § 195.450 to make these definitions apply wherever they are used throughout part 195.

In this NPRM, PHMSA proposes modifying the definition of HVL to include carbon dioxide (see section III.A.3). As a conforming change with this proposal, PHMSA proposes adding a parenthetical after HVL at I.B.(5) of Appendix C to Part 195 to note that carbon dioxide is included within the definition of HVL.

Appropriateness of Above Proposed Enhanced Integrity Management Requirements and Implementing Guidance

PHMSA expects the proposed amendments to IM program requirements and guidance would be reasonable, technically feasible, cost-effective, and practicable for affected carbon dioxide and hazardous liquid pipeline operators. PHMSA's proposed amendments at Appendices B and C to Part 195 would merely better align the characterization within IM program implementing guidance of the actual hazards to public safety and the environment from releases of pipeline-transported carbon dioxide. Similarly, PHMSA's proposed amendments at § 195.452(e)(1)(iv) and (i)(2)(iii) to add references to "deleterious constituents" merely clarify the scope of longstanding regulatory language in those sections to reflect the common-sense proposition that the risks to public safety and the environment from carbon dioxide and hazardous liquid pipeline releases arise not only from the commercially valuable commodity being transported, but other constituents within the product stream. Although PHMSA's proposed amendments of § 195.452 elsewhere to extend existing EFRD installation requirements to carbon dioxide pipelines (at § 195.452(i)(4)) and require all carbon dioxide pipelines that could affect an HCA to install fixed vapor detection and alarm systems at certain aboveground facilities (at § 195.452(i)(5)) may impose relatively greater compliance burdens on operators, PHMSA understands those requirements are consistent with voluntary commitments reasonably prudent operators of carbon dioxide pipeline operators take in ordinary course given the potential lost commercial value and hazards to public safety and the environment from releases from their pipelines.[272] That said, should an operator of any hazardous liquid carbon dioxide pipeline subject to the proposed amendments discussed above identify a compelling need for regulatory flexibility from one of those proposed requirements, the PSR provides for special permit procedures at § 190.341 to request a deviation.

Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed amendment to IM program requirements and guidance discussed above 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 believes that its proposed compliance timelines (based on an effective date of most of those

[272] See, e.g., section III.C.5 & footnote 143 (discussion of voluntary commitments to install fixed vapor detection and alarm systems taken by recent greenfield carbon dioxide pipeline projects); Navigator, IL Commerce Comm. Doc. No. 22-0497, "Prepared Direct Testimony of Stephen Lee in re Application for Certificate of Authority to Construct the Navigator Heartland Greenway Project in Illinois" at 9 (Sept. 9, 2022) (committing to installation of EFRDs pursuant to an "EFRD Analysis" exceeding PHMSA part 195 rupture mitigation valve installation requirements).

proposed requirements one year after the publication date of a final rule, and three years after the publication date of a final rule for the fixed vapor detection and alarm system installation—which would necessarily be in addition to the time since issuance of this NPRM) would provide affected operators ample time to manage any related compliance costs and implementation challenges.

H. Miscellaneous Conforming Revisions at Parts 190, 196, and 198, and Extension of Existing Requirements at Part 199—§§ 190.3, 190.236, 196.109, 198.3, and 198.55

Overview

PHMSA's proposed amendment to the definition of "carbon dioxide" at § 195.2 to include lower-purity carbon dioxide product streams and different phases of carbon dioxide (see section III.A) also warrants several miscellaneous conforming or clarifying amendments and discussions of part 190 emergency order procedures, part 195 annual user fee obligations, part 195 subpart G personnel qualification requirements, parts 196 and 198 damage prevention requirements, and part 199 drug and alcohol testing workplace program requirements.

1. Emergency Order Procedures—§§ 190.3 and 190.236

PHMSA's regulatory and enforcement procedural requirements at part 190 implement a variety of statutory authorities and procedural rights broadly applicable to any gas (including LNG and underground natural gas storage) or hazardous liquid (including carbon dioxide) "pipeline facility" subject to the Pipeline Safety Laws. Although the regulatory language in part 190 largely mirrors the broad statutory language, a handful of sections in part 190 include references to "pipeline facility" that could, when read against the distinction made in part 195 between carbon dioxide pipelines and other species of hazardous liquid pipelines, be read to suggest limitations on application of those sections, which are inconsistent with the Pipeline Safety Laws and longstanding understanding of the scope of part 190 enforcement and procedural requirements.

Specifically, PHMSA's emergency order procedures at §§ 190.236 and 190.237 elaborate on self-executing statutory language introduced in section 16 of the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (Pub. L. 114-83, codified at 49 U.S.C. 60117(p)) authorizing PHMSA to issue emergency orders imposing restrictions, prohibitions, and safety measures addressing imminent hazards caused by unsafe conditions or practices on any gas or hazardous liquid pipeline facilities. PHMSA subsequently issued rulemakings[273] governing its exercise of that authority, including a regulatory definition at § 190.3 for "imminent hazard" that largely mirrored the statutory use of that term, as well as procedures at §§ 190.236 and 190.237 for issuance and rescission of emergency orders. Notwithstanding the reference within the self-executing statutory language to "hazardous liquid pipeline facilities"—which, as discussed in section V.A below, is understood in the Pipeline Safety Laws to encompass hazardous liquid pipeline facilities transporting carbon dioxide—the regulatory language incorporated into §§ 190.3 and 190.236 did not explicitly mention carbon dioxide pipeline facilities but rather referred only to hazardous liquid pipeline facilities.

PHMSA therefore proposes in this NPRM to amend those regulatory provisions to explicitly reference carbon dioxide pipelines, consistent with the scope of the self-executing statutory language. Specifically, PHMSA proposes to amend the definitions of "emergency

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[273] PHMSA, Interim Final Rule: Enhanced Emergency Order Procedures, 81 FR 70980 (Oct. 14, 2016); PHMSA, Final Rule: Enhanced Emergency Order Procedures, 84 FR 52015 (Oct. 1, 2019).

order" and "imminent hazard" at § 190.3 to insert a reference to "carbon dioxide [pipeline facilities]" within the list of pipeline facilities on which an imminent hazard can arise and an emergency order be issued. PHMSA proposes a similar addition of an explicit reference to "carbon dioxide [pipeline facilities]" in § 190.236. No such conforming revision at § 190.237 is necessary, as its regulatory language follows the broad language in the statute. The proposed revisions would better align regulatory text with PHMSA's self-executing statutory authority to issue emergency orders. The proposed revisions may be particularly valuable as the anticipated buildout of carbon dioxide pipelines to connect CCUS infrastructure may attract new pipeline operators inexperienced in navigating both PHMSA regulations and the Pipeline Safety Laws to identify relevant legal obligations and procedures.

2. Operator User Fees

The Pipeline Safety Laws at 49 U.S.C. 60301 direct PHMSA to impose user fees on gas and hazardous liquid pipeline facilities (including hazardous liquid pipelines transporting carbon dioxide) to help cover the cost of its own pipeline safety programs, and, via grant funding, the costs of State pipeline safety programs. PHMSA has, since 1986, assessed those fees on a per-mile basis, calculated against the mileage of an operator's pipelines in-service at the end of each calendar year.[274] PHMSA sends each operator[275] an invoice by e-mail on or around April of each year with that operator's annual user fee. The per-mile user fee for operators of hazardous liquid

[274] RSPA, "Notice: Pipeline Safety User Fees," 51 FR 25782 (July 16, 1986).
[275] Operators newly-subject to part 195 due to this NPRM's proposed amendments to the regulatory definition of "carbon dioxide" would be required to request an operator identification number (OPID) no later than the effective date of any final rule pursuant to § 195.64.

pipeline facilities (including currently regulated carbon dioxide) for FY 2023 was $115.02 per mile.[276]

The proposed amendments to the regulatory definition of "carbon dioxide" at § 195.2 to encompass pipeline transportation of more carbon dioxide product stream compositions, as well as liquid- and gas-phase carbon dioxide, are likely to increase the entities and pipeline mileage subject to annual user fees. No regulatory text needs to be amended. Affected operators would receive their initial user fee assessments in the next regularly scheduled annual user fee assessment (usually around April) following the effective date of a final rule in this rulemaking proceeding. Anticipated changes in the risk profile of the U.S. carbon dioxide pipeline infrastructure accompanying the buildout of CCUS infrastructure (see section II.B) underscore the importance of ensuring adequate funding of its and States' pipeline safety programs, backstopping the safety of newly regulated carbon dioxide pipelines.

3. Qualification of Personnel—49 CFR part 195, subpart G

PHMSA regulations at part 195, subpart G prescribe minimum requirements governing the qualification by operators of part 195-regulated hazardous liquid pipeline facilities (including carbon dioxide pipeline facilities) by their own and contractor personnel performing "covered tasks" on their facilities; these regulations ensure a qualified work force and reduce the probability and consequence of accidents caused by human error.[277] The proposed amendments

[276] PHMSA, "Operator User Fee Assessment Information: Fiscal Year 2023 User Fee Assessment," https://www.phmsa.dot.gov/operator-resources/operator-user-fee-assessment-information) (last visited Sept. 21, 2023).
[277] RSPA, "Final Rule: Qualification of Pipeline Personnel," 64 FR 46853 (Aug. 27, 1999).

to the regulatory definition of "carbon dioxide" at § 195.2 encompass pipeline transportation of more carbon dioxide product stream compositions, as well as liquid- and gas-phase carbon dioxide, which would increase the pipeline facilities subject to subpart G qualification requirements without requiring any specific amendment of the subpart G regulatory language itself. The same reasoning supporting initial establishment of those requirements (and their subsequent revision over time) for currently regulated hazardous liquid pipeline facilities applies to carbon dioxide pipelines. Properly-administered personnel qualifications programs are essential in avoiding the significant risks to public safety and the environment (see sections II.A and II.B) involved in a release from any carbon dioxide pipeline as a result of human error. Extending subpart G requirements may be particularly valuable as the anticipated buildout of carbon dioxide pipelines to connect CCUS infrastructure may attract some new pipeline operators and personnel inexperienced with PHMSA's subpart G requirements as newly regulated carbon dioxide pipelines are built or converted to part 195 service.

PHMSA expects the proposed extension of subpart G personnel qualification program requirements would be reasonable, technically feasible, cost-effective, and practicable for affected operators. Personnel qualification programs are commonplace employment conditions in many sectors of the economy—many involving much lower risks to public safety and the environment than those involved in pipeline transportation of carbon dioxide—and newly regulated operators would be able to draw on a number of resources (e.g., PHMSA guidance, consultant expertise, industry guidelines and initiatives, personnel qualification programs in affiliated companies) when implementing and revising their own programs. Also, these requirements have a proven track record in ensuring public safety and environmental protection, as currently regulated carbon dioxide pipelines (as well as other hazardous liquid pipelines) have long been subject to those requirements. Therefore, operators' efforts to comply with PHMSA personnel qualification program requirements would be consistent with programs reasonably prudent operators of any carbon dioxide pipelines would undertake in ordinary course, given the risks involved in pipeline transportation of that commodity. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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, the proposed compliance timeline of the effective date of a final rule—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 compliant programs and manage any related compliance costs.

4. Damage Prevention—§§ 196.109, 198.3, and 198.55

PHMSA regulations at 49 CFR parts 196 and 198 implement statutory language in section 2 of the Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act of 2006 (Pub. L. 109-468) directing PHMSA to establish procedures for PHMSA's initiation of enforcement proceedings against excavators in States lacking adequate excavation damage prevention enforcement regimes.[278] Consistent with the statute's use of broad language (e.g., "pipeline facilities") encompassing both gas and hazardous liquid pipeline facilities (including carbon dioxide pipeline facilities) when identifying the underground pipelines which Congress intended to protect, PHMSA's implementing regulations explicitly mentioned carbon dioxide

[278] PHMSA, "Final Rule: Pipeline Damage Prevention Programs," 80 FR 43836 (July 23, 2015).

pipelines alongside gas and hazardous liquid pipelines within the regulatory definition of "pipeline" in part 196. However, regulatory language elsewhere in parts 196 and 198 inadvertently included qualifying language suggesting those sections may not be applicable to carbon dioxide pipelines. Specifically, §§ 196.109 (required excavator actions in response to release caused by excavation activities), 198.3 (definition of "underground pipeline facilities") and 198.55(a)(6)(iii)(B) (criteria for evaluation of State damage prevention enforcement programs) forego use of the broad regulatory definitions and refer only to "gas" and "hazardous liquid[s]." In addition to these issues, the proposed amendments to the regulatory definition of "carbon dioxide" at § 195.2 to encompass pipeline transportation of more carbon dioxide product stream compositions, as well as liquid- and gas-phase carbon dioxide, would in turn increase the pipeline facilities protected by requirements at 49 CFR parts 196 and 198.

PHMSA therefore proposes to amend §§ 196.109, 198.3, and 198.55(a)(6)(iii)(B) to revise language that could be read as excluding application of those provisions to carbon dioxide pipelines. PHMSA also understands its proposed extension of parts 196 and 198 requirements would be reasonable, technically feasible, cost-effective, and practicable for affected operators and States. These requirements are longstanding and have a proven track record in ensuring public safety and environmental protection in connection with protecting currently regulated carbon dioxide pipelines (as well as other hazardous liquid and gas pipelines) from excavation damage. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the proposed amendments would 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 of the effective date of a final rule—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 and States ample time to implement compliant programs and manage any related compliance costs.

5. Drug and Alcohol Workplace Testing Program Requirements—49 CFR part 199

For over thirty years, PHMSA regulations at part 199 have required operators of pipeline facilities subject to part 195 (including operators of hazardous liquid pipeline facilities transporting carbon dioxide) to implement workplace drug and alcohol testing programs for their personnel.[279] PHMSA's part 199 regulations incorporate by reference DOT-wide procedural requirements for workplace drug and alcohol testing programs in the transportation sector, as set forth at 49 CFR part 40.[280]

The proposed amendments to the regulatory definition of "carbon dioxide" at § 195.2 to encompass pipeline transportation of more carbon dioxide product stream compositions, as well as liquid- and gas-phase carbon dioxide, would increase the pipeline facilities subject to workplace drug and alcohol testing requirements at 49 CFR parts 40 and 199 without requiring specific amendments to the regulatory language in part 199 itself. The same reasoning supporting initial establishment of those requirements (and their subsequent revision over time) for currently regulated gas and hazardous liquid pipeline facilities also applies to carbon dioxide pipeline facilities, which this NPRM proposes to bring within part 195 safety regulations: properly

[279] RSPA, "Final Rule: Control of Drug Use in Natural Gas, Liquefied Natural Gas, and Hazardous Liquid Pipeline Operations," 53 FR 47084 (Nov. 21, 1988) (adopting § 199.1 imposing drug and alcohol testing programs on any pipeline facility "subject to part 192, 193, or 195 . . . .") .
[280] DOT requirements were last updated in May 2023. DOT, "Final Rule: Procedures for Transportation Workplace Drug and Alcohol Testing Programs: Addition of Oral Fluid Specimen Testing for Drugs," 88 FR 27596 (May 2, 2023).

administered drug and alcohol testing is critical in avoiding the significant risks to public safety and the environment (see sections II.A and II.B) involved in a release from a carbon dioxide pipeline.

PHMSA expects the proposed extension of PHMSA and DOT drug and alcohol testing program requirements would be reasonable, technically feasible, cost-effective, and practicable for affected operators. Mandatory drug and alcohol testing programs are commonplace employment conditions in many sectors of the economy—many involving much lower risks to public safety and the environment than those involved in pipeline transportation of carbon dioxide—and newly regulated operators would be able to draw on a number of resources (e.g., consultants, industry guidelines, industry trade groups, programs in affiliated companies) when implementing or revising their own programs. The requirements at issue have a proven track record in ensuring public safety and environmental protection, as currently regulated carbon dioxide pipelines (as well as other hazardous liquid and gas pipelines) have long been subject to those requirements. Therefore, operators' efforts to comply with DOT and PHMSA drug and alcohol testing program requirements would be consistent with the actions reasonably prudent operators of any carbon dioxide pipelines would undertake in ordinary course, given the risks involved in pipeline transportation of that (asphyxiating) commodity. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 of the effective date of a final rule—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 compliant drug and alcohol testing programs and manage any related compliance costs.

I. Miscellaneous Amendments Related to Hazardous Liquid Gathering Lines—§§ 195.2, 195.402, and 195.417

A part 195-regulated gathering line is defined at § 195.2 as "a pipeline 219.1 mm (8-5⁄8 in) or less [in] nominal outside diameter that transports petroleum from a production facility." Gathering lines meeting the additional definition of a "regulated rural gathering line" at § 195.11 must comply with specific requirements listed at § 195.11. Likewise, gathering lines meeting the additional definition of a "reporting-regulated-only gathering line" at § 195.15 must only comply with the requirements specified at § 195.15. Other gathering lines not meeting these definitions (non-rural gathering lines at § 195.1(a)(4)(i), and gathering lines located in inlets to the Gulf of Mexico at § 195.1(a)(4)(iii)) must comply with all applicable requirements of part 195.

In April 2022, the Valve Rule was published to the Federal Register. Among the regulatory amendments adopted in the Valve Rule were: enhanced emergency planning, response, and notification requirements applicable to all part 195-regulated carbon dioxide and hazardous liquid pipeline operators (including operators of non-rural gathering lines and gathering lines located in inlets to the Gulf of Mexico) subject to § 195.402, to include new references to public safety answering points (such as 9-1-1 call centers); a requirement for those operators to update their written procedures to provide for timely rupture identification; a handful of new, implementing definitions at § 195.2 applicable to all part 195-regulated pipelines (including gathering lines); and a definition of the term "Notification of potential rupture" at a new § 195.417.

The D.C. Circuit, however, vacated those new requirements for all hazardous liquid gathering lines in a decision issued in May 2023.[281] PHMSA subsequently issued a Technical Correction codifying the court's decision by introducing exceptions to the above provisions, among others, which restricted their application to part 195-regulated hazardous liquid gathering lines.[282] The Technical Correction introduced language at each of the § 195.2 definitions adopted in the Valve Rule ("Entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments"; "Notification of potential rupture"; and "Rupture-mitigation valve") excepting all part 195-regulated gathering lines from those definitions. The Technical Correction also introduced a series of exceptions for hazardous liquid gathering lines at §§ 195.402 and 195.417 regarding emergency response and notification and rupture identification procedures. The Technical Correction's exceptions do not distinguish between different species of part 195-regulated gathering lines, including non-rural gathering lines (§ 195.1(a)(4)(i)), gathering lines located in inlets to the Gulf of Mexico (§ 195.1(a)(4)(iii)), regulated rural gathering lines (§ 195.11), and reporting-regulated-only gathering lines (§ 195.15).

PHMSA is not proposing in this NPRM to restore applicability of other regulatory amendments adopted in the Valve Rule pertaining to rupture-mitigation valve installation, operation, and maintenance to any part 195-regulated hazardous liquid gathering lines. Similarly, PHMSA is not proposing to restore application of the failure investigation requirements adopted in the Valve Rule at § 195.402(c)(5) to any gathering lines.

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[281] *GPA Midstream Assn. v. Dep't of Transp.*, 67 F.4th 1188, 1201 (D.C. Cir. 2023).
[282] PHMSA, "Final Rule: Requirement of Valve Installation and Minimum Rupture Detection Standards: Technical Corrections," 88 FR 50056 (Aug. 1, 2023).

Written emergency planning, response, and notification procedures are critical tools for the safe operation of any hazardous liquid pipeline. Non-rural gathering lines and gathering lines located in inlets to the Gulf of Mexico were already subject to extensive emergency planning, response, and notification requirements before the issuance of the Valve Rule in April 2022, consistent with the risks to public safety and the environment posed by an emergency involving those facilities.[283] Those long-standing safety standards included requirements obliging operators to have written emergency procedures for notifying, establishing, and maintaining communications with fire, police, and other public officials (§ 195.402(c)(12) and (d)(7)); taking actions necessary to minimize hazards to public safety from the emergency (§ 195.402(e)(2) and (4)-(5)); and directing operator control room response actions in an emergency (§ 195.402(c)(15)).

The amendments at § 195.402 introduced in the Valve Rule were modest additions to those long-standing emergency planning, response, and notification requirements. The Valve Rule, at § 195.402(c)(12), (e)(1), and (e)(7), added language requiring notification of, and communication with, PSAPs or emergency coordination agencies to 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.[284] The Valve Rule also made a pair of incremental changes at § 195.402(e)(10)'s requirement that operator procedures include taking certain actions—emergency shutdown or pressure reduction—to minimize public safety risks in an emergency. The first change was to

[283] Regulated rural and reporting-regulated-only gathering lines were not subject to such requirements in § 195.402.
[284] 87 FR at 20969-70, 20976.

add language ("including, but not limited to. . .") clarifying that operator procedures could include actions 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 added action of valve shut-off. The second change updated the list of hazards operators must minimize to include environmental hazards, as the mechanism for public safety and environmental harms (namely, the release of transported product from a pipeline) is identical.

The Valve Rule also made several regulatory amendments to address the time-dependent[285] risks to public safety and the environment posed by ruptures on carbon dioxide and hazardous liquid pipelines, including gathering lines. First, the Valve Rule added at § 195.2 (which in turn references a new § 195.417) the new term "Notification of potential rupture" codifying commonly-understood indicators of a rupture.[286] The Valve Rule also added a pair of requirements ensuring timely identification of, and response to, potential ruptures, in which every second lost can increase public safety and environmental consequences: (1) a new § 195.402(e)(4) requiring operators develop procedures for confirming actual ruptures following reports of the indicators listed in the new definition of "Notification of potential rupture"; and (2) language at § 195.402(e)(7) requiring immediate and direct notification by the operator to PSAPs upon the notification of a potential rupture.[287] Similarly, PHMSA enhanced a longstanding

[285] The severity of harms to public safety and the environment from a rupture on a hazardous liquid pipeline depend on the volume of product released, the duration of the release, and the time before mitigation/response actions are initiated and completed.
[286] 87 FR at 20949-52, 20974, 20976.
[287] 87 FR 20952-53.

requirement at § 195.402(e)(10) governing emergency procedures for control room personnel by adding a cross-reference to newly-adopted provisions relating to RMVs at §§ 195.418 and 195.446. Lastly, the Valve Rule adopted certain other definitions of terms ("Entirely replaced onshore hazardous liquid or carbon dioxide segment"; and "Rupture-mitigation valve") used in its regulatory amendments.

PHMSA now proposes several amendments to restore certain emergency planning, response, and notification procedures vacated by the D.C. Circuit with respect to certain hazardous liquid gathering lines. First, PHMSA proposes to delete from each of the § 195.2 definitions introduced in the Technical Correction language excluding application of those terms to any part 195-regulated gathering line.[288] PHMSA proposes to make a conforming deletion of a similar disclaimer at § 195.417(c). Second, PHMSA proposes to delete from § 195.402 the Technical Correction's addition of a new paragraph (g) excluding application of the Valve Rule's amendments at § 195.402 discussed above to hazardous liquid gathering lines (other than regulated rural gathering lines and reporting-regulated-only gathering lines, which are excluded by operation of other provisions of part 195). PHMSA expects that these proposed revisions that would restore emergency planning, notification, and response (including rupture identification) procedures for non-rural gathering lines (described at § 195.1(a)(4)(i)) and gathering lines located in inlets of the Gulf of Mexico (described at § 195.1(a)(4)(iii)), thereby reducing the delays associated with identifying and responding to ruptures and other emergencies which can and do take place on gathering lines. PHMSA expects that those improved emergency planning,

[288] PHMSA understands that in so doing, the § 195.417 definition of "Notification of potential rupture" referenced within § 195.2 would apply to all part-195 regulated gathering lines as well.

notification, and response procedures will reduce time-dependent public safety and environmental consequences, as prompt notification and response actions following an accident on those pipelines can have outsized benefits in reducing the volume of product released to the environment and ensuring that persons in affected areas can take action to minimize their own exposure. Further, this proposal is focused on application of these emergency planning, response, and notification provisions to non-rural gathering lines (§ 195.1(a)(4)(i)) and gathering lines located in inlets of the Gulf of Mexico (§ 195.1(a)(4)(iii)).

PHMSA expects these proposed amendments would be reasonable, technically feasible, cost-effective, and practicable for affected gathering line operators. As explained above, the Valve Rule's amendments at §§ 195.2, 195.402, and 195.417 are incremental improvements on existing requirements applicable to non-rural gathering pipelines (§ 195.1(a)(4)(i)) and gathering pipelines located in inlets to the Gulf of Mexico (§ 195.1(a)(4)(iii)). Some of those amendments are broad in scope and are applicable to any emergency on those pipelines; others are specific to ruptures on those pipelines. Each of those amendments are common-sense expectations ensuring operator emergency planning, response, and notification procedures are directed toward timely and effective response and mitigation of risks to public safety and the environment. Further, the restoration of definitions at § 195.2 do not themselves entail compliance burdens for operators apart from the operative provisions in which they are employed. Although the restored applicability of the Valve Rule's revisions at §§ 195.402 and 195.417 could entail additional compliance burdens for affected gathering line operators (non-rural gathering lines and gathering lines located in inlets to the Gulf of Mexico), some operators may already incorporate the required content in their pipelines' emergency planning, response, and notification procedures. A reasonably prudent operator of any hazardous liquid pipeline facility would maintain such procedures as standard practice, given that their systems transport commercially valuable, pressurized, and hazardous products. Viewed against those considerations and the compliance costs estimated in the PRIA, PHMSA expects the 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 of the effective date a final rule (one year after the publication of a final rule) would provide operators ample time to implement necessary changes to their procedures (as well as manage any resulting compliance costs).

J. Summary of Proposals for Hazardous Liquid Pipelines

As carbon dioxide pipelines currently represent a small portion of the pipeline mileage regulated by part 195, and the main focus of this NPRM is on proposals related to carbon dioxide pipelines, PHMSA has provided the following list to aid operators of hazardous liquid pipelines in their review of this NPRM, including operators of hazardous liquid gathering lines. Briefly, the sections containing proposals which may be applicable to operators of hazardous liquids pipelines, including operators of hazardous liquid gathering lines, are: §§ 195.2 (definitions of "Close interval survey", "Notification of potential rupture", "Entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments", and "Rupture-mitigation valve" only), 195.3(g)(2), 195.5(a)(3), 195.18, 195.48, 195.49, 195.54, 195.55(b)(1), 195.116, 195.120(b)(4), 195.248, 195.263, 195.309, 195.402(c)(5)(iv), 195.402(c)(14), 195.402(e)(3), 195.402(g), 195.403(a)(4), 195.412, 195.417(c), 195.429, 195.450, 195.452(e)(1)(iv), 195.452(f)(1), 195.452(i)(1), 195.452(i)(2)(iii), 195.452(i)(5), 195.456, and 195.588. Some proposals are specific to HVL pipelines, while other proposals encompass all hazardous liquid pipelines, including hazardous liquid gathering lines. Further detail on these proposals can be found within section IV of this NPRM, or within the relevant sub-sections of section III.

IV. Section-by-Section Analysis

§ 190.3 Definitions.

This provision contains definitions for regulatory language used throughout part 190 (pipeline safety enforcement and regulatory procedures). PHMSA proposes to amend the definitions of "emergency order" and "imminent hazard" to more clearly communicate that hazardous liquid pipelines transporting carbon dioxide are among those hazardous liquid pipeline facilities addressed by this provision.

§ 190.236 Emergency Orders: Procedures for issuance and rescission.

This provision establishes procedures governing PHMSA's exercise of its emergency order authority to address an imminent hazard on gas and hazardous liquid pipeline facilities. PHMSA proposes to amend the regulatory language at § 190.236(d) to more clearly communicate that hazardous liquid pipelines transporting carbon dioxide are among those hazardous liquid pipeline facilities addressed by this provision.

§ 195.1 Which pipelines are covered by this Part?

Section 195.1 details the pipelines for which part 195 regulations are applicable, as well as the pipelines that are excluded from part 195 regulations. In this rulemaking, PHMSA proposes to include a new exception at § 195.1(b)(11) pertaining to pipelines transporting carbon dioxide that aligns with the statutory text at 49 U.S.C. 60102(i)(3). PHMSA additionally proposes a corresponding change to the existing exception at § 195.1(b)(8) to relocate the reference to "or carbon dioxide" in this exception to the new paragraph § 195.1(b)(11). PHMSA also proposes a new exception at § 195.1(b)(10)(iii) for pipelines transporting carbon dioxide downstream of the pipeline isolation valve located at an injection wellhead used for carbon dioxide storage. Finally, PHMSA proposes a change to the title of part 195 to include carbon dioxide: "Transportation of Hazardous Liquids and Carbon Dioxide by Pipeline."

§ 195.2 Definitions.

Section 195.2 provides definitions for various terms used throughout part 195. In support of other regulations proposed in this NPRM, PHMSA is proposing to amend the definitions of "Carbon dioxide," "Highly volatile liquid or HVL," "Line section," "Pipeline or pipeline system," and add a new definition for "Close interval survey." PHMSA is also proposing to delete exclusions from certain definitions introduced in an earlier rulemaking, which had codified the results of judicial review of PHMSA's April 2022 Valve Rule: "Entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments"; "Notification of potential rupture"; and "Rupture-mitigation valve."

PHMSA proposes several changes to the regulatory definitions at § 195.2 to expand part 195's scope to apply to pipelines transporting carbon dioxide in the gas and liquid phases. First, the definition of "carbon dioxide" would be changed to: (1) include gas- and liquid-phase carbon dioxide in addition to (currently-regulated) supercritical-phase carbon dioxide, and, (2) reduce the minimum required concentration of carbon dioxide molecules within a product stream for a pipeline to be subject to part 195 regulation as a "carbon dioxide" pipeline to "more than 50 percent" (from the current threshold of "more than 90 percent"). PHMSA's proposed amendments to the regulatory definition of "carbon dioxide" at § 195.2 to encompass pipeline transportation of more carbon dioxide product stream compositions, as well as liquid- and gas-phase carbon dioxide, will (without the need for amendment of regulatory text) also increase the entities subject to: annual user fees; miscellaneous part 195 requirements, including (but not limited to) those pertaining to subparts B (accident and other reporting), F (operations and maintenance), and G (personnel qualification); parts 196 and 198 damage prevention requirements; and part 199 workplace drug and alcohol testing program requirements.

Second, the definition of "highly volatile liquid or HVL" would be changed to state explicitly that all carbon dioxide pipelines will be considered HVL lines under part 195. Third, PHMSA proposes to make conforming revisions to miscellaneous definitions ("Line section" and "Pipeline" or "pipeline system") to include compressor stations and compressing units to reflect the addition of a gas-phase commodity (carbon dioxide) to part 195. Fourth, PHMSA proposes to add a new definition of "Close interval survey" to clarify use of this term in other regulatory amendments proposed in this NPRM.

Fifth, PHMSA proposes to remove language excluding application to hazardous liquid gathering lines of certain definitions ("Entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments"; "Notification of potential rupture"; and "Rupture-mitigation valve") that had been adopted in the Valve Rule but were subsequently vacated for gathering lines as a result of judicial review of that rulemaking.

§ 195.3 What documents are incorporated by reference partly or wholly in this part?

Section 195.3 lists documents that are incorporated by reference in part 195. PHMSA is proposing to make conforming amendments at § 195.3 to reflect other proposed changes made in this NPRM. API Specification 5L, Specification for Line Pipe, prescribes the minimum requirements for the manufacture of new seamless and welded steel line pipe. The standard is already incorporated by reference in part 195. In this NPRM, PHMSA is proposing to incorporate this standard by reference into the fracture propagation requirements at § 195.111.

§ 195.5 Conversion to service subject to this part.

Section 195.5 prescribes the minimum requirements for the conversion of a pipeline to service under part 195 that was not previously in part 195-regulated hazardous liquid or carbon dioxide service. PHMSA is proposing that all pipelines being converted to transport hazardous liquid or carbon dioxide under part 195 meet the design and construction requirements for new, replaced, or relocated pipeline segments to ensure all newly converted pipelines are updated to include these safety-supporting design and construction requirements. PHMSA is also proposing to expand the requirements applicable to pipelines being converted to transport carbon dioxide in particular, including the following new requirements: substantiate MOP and conduct a hydrostatic spike test before conversion; perform cathodic protection and pipeline coating surveys within 15 months following conversion; inspect the pipeline being converted with an instrumented ILI tool within 12 months after conversion; and remediate any conditions affecting the safe operation of the pipeline that are discovered.

§ 195.8 Transportation of hazardous liquid or carbon dioxide in pipelines constructed with other than steel pipe.

Section 195.8 allows for the transportation of hazardous liquids and supercritical-phase carbon dioxide in non-steel pipelines with a required notification to the PHMSA Administrator. PHMSA is proposing a conforming change to the effective dates in this section to allow for the transportation of gas- and liquid-phase carbon dioxide in non-steel pipelines, consistent with the new definition change for carbon dioxide at § 195.2. In addition, PHMSA proposes to replace a pronoun referring to the PHMSA Administrator with the agency name and require notifications to include the phase of carbon dioxide transported, if applicable.

§ 195.18 How to notify PHMSA.

Section 195.18 provides the requirements for notifications to PHMSA required by part 195. In this rulemaking, PHMSA proposes to add § 195.5 to the list of sections for which § 195.18(c) is applicable. PHMSA also proposes at § 195.18(c) changing "letter" to "response," "the Associate Administrator of Pipeline Safety" to "PHMSA," and "additional time and/or information" to "additional time or additional information" to allow more timely responses from PHMSA to operators providing such notifications to PHMSA.

§ 195.48 Scope.

Section 195.48 provides the scope and applicability of Subpart B, "Annual, Accident, and Safety-Related Condition Reporting." In this rulemaking, PHMSA proposes a correction to the title of the annual report form to "DOT Form PHMSA F 7000-1.1."

§ 195.49 Annual Report.

This section prescribes when and how an operator must complete DOT Form PHMSA F 7000-1.1, also called the annual report. PHMSA is proposing to remove an outdated reference to the deadline for the 2010 annual report. Additionally, this rulemaking proposes to require operators of carbon dioxide pipelines to submit annual reports solely under the commodity type of carbon dioxide by clarifying the separate reporting requirement for HVLs is for non-carbon dioxide HVLs only. This conforming change prevents duplicative reporting by operators.

§ 195.54 Accident Reports.

Section 195.54 requires operators to submit accident reports within 30 days of the date of the accident when reporting is required under § 195.50. PHMSA has two separate accident report forms (DOT Form PHMSA F 7000-1 and DOT Form PHMSA F 7000-2) for use by operators depending on the type of pipeline on which the accident occurred. In this rulemaking, PHMSA proposes correcting the existing single report title to reflect the two different accident reports and noting which group of pipelines each is applicable, for operator clarity.

§ 195.55 Reporting safety-related conditions.

Section 195.55 prescribes which SRCs an operator is required to report as well as when operators are exempted from making those reports. With some exceptions, SRC reports are not required for conditions occurring on pipelines that are more than 220 yards from any building intended for human occupancy or outdoor place of assembly, regardless of the product transported. Regardless of the distance from the pipeline, however, SRC reports are required when the condition occurs within the right-of-way of an active railroad, paved road, street, or highway, or when they occur offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water. In this NPRM, PHMSA is proposing to remove the distance-based exception for pipelines transporting HVLs only, including carbon dioxide, such that those operators would need to submit SRC reports for conditions occurring on those pipelines regardless of the distance from any building intended for human occupancy or outdoor place of assembly.

§ 195.61 National Pipeline Mapping System.

Section 195.61 prescribes the requirements for operators of hazardous liquid pipeline facilities to provide and update previously submitted geospatial data to PHMSA. In this rulemaking, PHMSA proposes to clarify that operators of all part 195-regulated pipeline facilities, including carbon dioxide pipeline facilities, would need to submit geospatial data according to the requirements of § 195.61.

§ 195.111 Fracture propagation.

Section 195.111 requires that pipelines transporting carbon dioxide be designed to mitigate fracture propagation. This rulemaking proposes to enhance this section by providing explicit requirements on how the mitigation of fracture propagation must be accomplished on carbon dioxide pipelines that are newly constructed, replaced, relocated, otherwise changed, or converted to service; these requirements mirror the fracture control measures found in the design criteria for pipelines operating under an alternative MAOP in the gas pipeline safety regulations under § 192.112(b).

First, PHMSA proposes to require operators to consider the full range of relevant parameters to which the pipe will be exposed over its operating lifetime when evaluating resistance to fracture initiation. Second, PHMSA proposes to require operators to ensure fracture arrest within a certain pipe length to prevent long running fractures. Third, PHMSA proposes that the pipe would have to pass several tests designed to reduce the risk that fractures would initiate and ensure plastic deformation before fracture. Fourth, PHMSA proposes pipe toughness properties meet the requirements of API Specification 5L. Fifth, to the extent it would be physically impossible for a particular pipe to meet toughness standards under certain conditions, PHMSA proposes that operators use crack arrestors to halt a fracture within a specified length. Lastly, operators of carbon dioxide pipelines meeting the existing definition of carbon dioxide (a fluid consisting of greater than 90 percent carbon dioxide molecules compressed to a supercritical state) would still be required to design those pipelines to mitigate fracture propagation, as PHMSA proposes to retain the existing language, modified to reflect applicability.

§ 195.116 Valves.

Section 195.116 prescribes the minimum design characteristics and capabilities for all valves on pipelines operated under part 195. Paragraph (c) requires that each part of the valve that will be in contact with the transported product(s) be compatible with that product(s). In this NPRM, PHMSA proposes to expand this requirement to include compatibility with the entirety of the product stream, which could include non-predominant commodities, meaning commodity products that do not make up most of the product stream, and contaminants, such as hydrogen sulfide or water. This proposal would be applicable to pipelines transporting carbon dioxide or hazardous liquids.

§ 195.120 Passage of internal inspection devices.

Section 195.120 details when a pipeline must be designed to accommodate internal inspection devices, also known as ILI tools. This NPRM proposes a conforming change at §195.120(b)(2) to add compressor stations to the list of excepted station piping, consistent with the addition of the gas phase to the definition of carbon dioxide at § 195.2. PHMSA also proposes a clarifying change at § 195.120(b)(4) to provide examples of crossovers, such as at mainline valves and between parallel pipelines.

§ 195.134 Leak detection.

Section 195.134 prescribes which pipelines are required to have leak detection systems compliant with § 195.444 and API RP 1130. Currently, § 195.134 is applicable to pipelines transporting hazardous liquids without gas in the liquid and excludes offshore gathering or rural regulated gathering lines.

In this NPRM, PHMSA proposes the use of leak detection systems on all pipelines transporting carbon dioxide. Pipelines transporting carbon dioxide (in any phase) that were constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5 prior to the effective of a final rule would have 4 years from that effective date to install a leak detection system. Pipelines transporting carbon dioxide (in any phase) constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5 on or after the effective date of a final rule would have to install a leak detection system by that effective date. This NPRM also proposes that the leak detection systems on pipelines transporting supercritical- or liquid-phase carbon dioxide must be CPM leak detection systems, which would be required to meet the requirements of §§ 195.134(c) and 195.444(c) (and by extension, API RP 1130).

§ 195.210 Proximity to residences and other places.

Section 195.210 directs operators of new carbon dioxide and hazardous liquid pipelines to select pipeline right-of-way to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. Further, should an operator select a right-of-way that is located within 50 feet (15 meters) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, the operator must provide the pipeline with at least 12 inches (305 millimeters) of cover in addition to the cover required by § 195.248.

This NPRM proposes to add a new requirement for operators of onshore carbon dioxide pipelines newly constructed replaced, relocated, otherwise changed, or converted to service under § 195.5 that select a right-of-way that is located within 2 miles (3.22 kilometers) of any residence, business, or place of public assembly to document the reasons such a location was impracticable to avoid. This NPRM also proposes to require that those operators perform a population density survey along the pipeline route to establish an emergency planning zone, which would include surveying all buildings intended for human occupancy (including residences and businesses) and places of public assembly within two miles on either side of the pipeline centerline. The population density survey would collect data including: the number of affected entities (including any residents or occupants); their ages; preferred language; primary and secondary phone numbers; any specific evacuation information, such as special access routes into buildings; and if additional help in evacuation is required. This NPRM also proposes to require those carbon dioxide pipeline operators to distribute emergency response information meeting the requirements at § 195.440(d), (f), and (g) to each building intended for human occupancy (including residences and businesses) and place of public assembly identified during the population density survey before initial operation of the carbon dioxide pipeline. Finally, for those buildings (including residences and businesses) and places of public assembly in locations that an operator has determined could be affected by the release of carbon dioxide from its pipeline (as determined by this NPRM's proposed amendments at §§ 195.452(f)(1) and 195.456(b)), that emergency response information must include an explicit statement of that determination and provide additional precautions the public in those locations should take in the event of an emergency.

Lastly, PHMSA proposes clarifications at paragraphs (a) and (b) of § 195.210 and a change to the section title. PHMSA has proposed retitling § 195.210 to "Proximity to residences and other places" to better clarify the intent of the section and the scope of the requirements within. PHMSA has proposed replacing "private dwellings" with the more commonly used term "residences" and "industrial buildings" with the more commonly used term "businesses" throughout § 195.210(a) and (b). PHMSA has also proposed clerical edits throughout § 195.210(b) to use the active voice.

§ 195.248 Cover over buried pipeline.

Section 195.248 specifies the burial depth requirements for new pipelines. This NPRM proposes to add a new row to the table of locations and corresponding depth of cover for agricultural areas. This proposal includes a requirement that all pipelines to which this section is applicable, including carbon dioxide pipelines, hazardous liquid pipelines, and gathering lines, must be installed so that the cover between the top of the pipe and the ground level, roadbed, river bottom, or underwater natural bottom (as determined by recognized and generally accepted practices), as applicable, complies with a minimum depth of 48 inches (1,219 millimeters) for normal excavation in agricultural areas. Rock excavation would not be applicable for this location category.

§ 195.260 Valves: location.

Section 195.260 specifies the locations where valves are required to be installed, including the maximum spacing between valves. This NPRM proposes to add the suction and discharge ends of compressor stations to the list of required valve locations at § 195.260(a). This proposal is a conforming change to reflect the proposed addition of the gas phase to the definition of carbon dioxide and also addresses the asphyxiation potential of carbon dioxide. This NPRM also proposes to add a clarifying statement at § 195.260(g) that notes that pipelines transporting carbon dioxide are included within the definition of pipelines transporting HVLs, as a conforming change with the proposed change to the definition of HVL at § 195.2.

§ 195.262 Pumping equipment.

Section 195.262 outlines the basic safety equipment required at pump stations, including adequate ventilation, emergency shutdown capabilities, overpressure safety devices, and fire protection equipment. Reflecting the proposed change to the definition of carbon dioxide, PHMSA is proposing conforming changes at § 195.262 to require the use of this safety equipment at compressor stations as well as pump stations. PHMSA is also proposing a change to the title of this section to reflect the proposed expanded scope.

§ 195.263 Fixed vapor detection and alarm systems.

Section 195.263 is a new section proposed under part 195, subpart D to require pipelines transporting HVLs (including carbon dioxide) that are constructed, replaced, relocated, otherwise changed, or converted to service on or after the effective date of a final rule to have fixed vapor detection and alarm systems. The new proposed section prescribes the capabilities of the required vapor detection and alarm systems, which include: (1) being able to monitor transported products or constituents that might be deleterious to public safety or the environment; (2) continuous monitoring for concentrations approaching hazardous or flammable/combustible thresholds; (3) providing warnings and alarms to persons inside or near certain pipeline facilities; and (4) providing a notification to the operator's operational control center.

§ 195.302 General requirements.

Section 195.302 states that pipelines operating under part 195 must have a subpart E pressure test completed prior to service, provides compliance dates for those pressure tests, and specifically lists which pipelines are excepted from this requirement. Paragraph (b), which outlines the excepted pipelines, includes two exceptions at paragraph (b)(2) for pipelines transporting carbon dioxide that were constructed prior to July 12, 1991: (i) those with a MOP established in accordance with § 195.406(a)(5), and (ii) those located in a rural area as part of a production field distribution system.

Due to the proposed change in the definition of carbon dioxide, additional existing pipelines may become regulated under part 195, some of which may be excepted from pressure tests pursuant to § 195.302(b). This NPRM proposes to reflect these newly excepted carbon dioxide pipelines by restructuring paragraph (b)(2) into three subparagraphs instead of the previous two: (i) pipelines transporting carbon dioxide meeting the existing definition, (ii) pipelines transporting supercritical-phase carbon dioxide meeting the new definition proposed in this NPRM, and (iii) pipelines transporting gas- or liquid-phase carbon dioxide meeting the new definition proposed in this NPRM.

This NPRM also proposes to move the statement that these newly excepted carbon dioxide pipelines must have a MOP determined in accordance with § 195.405(a)(5) into the introductory text of paragraph (b)(2), consistent with the structure of (b)(1). This proposal would make the original (b)(2)(ii), which contains the exception for carbon dioxide pipelines in a rural area as part of a production field distribution system, no longer applicable under the proposed changes to (b)(2), as PHMSA does not require those pipelines to have a MOP determined in accordance with § 195.405(a)(5). As such, PHMSA is proposing to move this exception to a new paragraph §195.302(b)(5). This proposal would not change the pressure test exception for those pipelines or the requirements regarding their MOP determination.

§ 195.306 Test medium.

Section 195.306 prescribes the acceptable test mediums for pressure tests performed under subpart E of part 195. Paragraph (c) and its subparagraphs provide alternatives to water as the test medium when pressure testing carbon dioxide pipelines under specific circumstances. PHMSA proposes in this NPRM to remove carbon dioxide as an acceptable test medium for pressure tests on carbon dioxide pipelines. The ability for operators of carbon dioxide pipelines to use inert gas (specifically excluding carbon dioxide, which PHMSA does not consider to be an inert gas) when pressure testing carbon dioxide pipelines, should they meet the requirements of § 195.306(c)(1) through (5), would remain unchanged.

§ 195.309 Spike hydrostatic pressure test.

Section 195.309 is a new section being added to part 195, subpart E to create a single, centralized section that contains the requirements for spike hydrostatic pressure testing. In other sections of the code where spike hydrostatic pressure testing is required, PHMSA is proposing references to § 195.309 (see proposed §§ 195.5 and 195.588).

§ 195.401 General requirements.

Section 195.401 contains general requirements for pipelines operating under part 195, whether they are transporting hazardous liquids or carbon dioxide. Paragraph (c) restricts operators from operating pipelines that do not meet the design and construction requirements of part 195, except for excepted pipelines and as provided at § 195.5.[289] Subparagraph (c)(4) states the exception date for carbon dioxide pipelines. Notably, "carbon dioxide" at § 195.401(c)(4) refers to the existing definition of carbon dioxide: a fluid consisting of greater than 90 percent carbon dioxide molecules compressed to a supercritical state. As this NPRM proposes to modify the definition of carbon dioxide, existing pipelines which transport carbon dioxide meeting the proposed definition, but not the existing definition, could become regulated. These pipelines include those transporting supercritical-phase carbon dioxide in percentages greater than 50

[289] In this case, "excepted pipelines" means pipelines in existence before PHMSA exercised its statutory authority to regulate those pipelines. PHMSA is restricted in which regulations it can apply retroactively to these pipelines.

percent and equal or less than 90 percent carbon dioxide (e.g., 65 percent carbon dioxide) and those transporting carbon dioxide in either the gas or liquid phases.

In this NPRM, PHMSA proposes adding two new subparagraphs at § 195.401(c) and modifying subparagraph (c)(4). PHMSA proposes modifying subparagraph (c)(4) to further clarify that "carbon dioxide" in that subparagraph is consistent with the existing definition: a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state. Pipelines transporting all other carbon dioxide meeting the proposed new definition of this NPRM would have exception dates defined in (c)(6) – supercritical phase greater than 50 and less than or equal to 90 percent carbon dioxide, or (c)(7) – gas or liquid phase greater than 50 percent carbon dioxide. The exception date for these pipelines at (c)(6) and (c)(7) would be the effective date of a final rule. These proposed changes are considered conforming changes for consistency with the proposed changes at § 195.2.

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

Section 195.402 prescribes the requirements for procedural manuals for normal operations and maintenance as well as abnormal operations and emergencies. These manuals must include specific procedures addressing normal operations and maintenance as detailed in paragraph (c) and emergencies as detailed in paragraph (e), among other categories.

This NPRM proposes to modify § 195.402(c)(14), which lists the equipment all operators of part 195-regulated hazardous liquid and carbon dioxide pipelines must provide to protect personnel in excavated trenches, when appropriate. PHMSA proposes to add two additional categories of equipment: (1) fire control equipment, and (2) devices capable of detecting hazardous concentrations of vapor or gas.

This NPRM also proposes to add a new subparagraph (c)(16) to require carbon dioxide pipeline operators have and follow procedures to provide local emergency response organizations with necessary equipment, tools, instruments, and materials necessary for responding to a carbon dioxide pipeline emergency. At § 195.402(c)(16), PHMSA also proposes carbon dioxide pipeline operators train local emergency response organizations on the use of the provided equipment, tools, instruments, and materials.

This NPRM also proposes to add a new § 195.402(c)(17) which requires onshore carbon dioxide pipeline operators to perform a population density survey along the pipeline route to establish, and subsequently update annually, an emergency planning zone. Operators of onshore carbon dioxide pipelines newly constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5 will be required to perform this survey prior to commencing initial operations after construction under the requirements at § 195.210. This information will be used to perform notifications to the public and emergency responders under the requirements proposed at § 195.402(e)(9).

Section 195.402(e)(3) requires hazardous liquid and carbon dioxide pipeline operators to have personnel, equipment, instruments, tools, and material available as needed at the scene of an emergency. PHMSA proposes to add that those instruments and tools must include devices capable of detecting flammable, asphyxiating, or toxic concentrations of hazardous liquid or carbon dioxide, as well as any deleterious constituents in the product stream.

Paragraph (e)(8) requires operators to use appropriate instruments to assess the extent and coverage of the vapor cloud and determine hazardous areas in the event of a failure on a pipeline transporting an HVL. PHMSA proposes additional text at paragraph (e)(8) to clarify that carbon dioxide is an HVL. This is a conforming change with the edits to the definition of HVL at § 195.2.

PHMSA also proposes the addition of a new subparagraph (e)(9) and renumbering of existing subparagraphs (e)(9) and (e)(10) to (e)(10) and (e)(11), respectively. At § 195.402(e)(9), PHMSA proposes to require onshore carbon dioxide pipeline operators to initiate an automatic notification system to provide affected entities (including, but not limited to, the general public) in the vicinity of the pipeline with direct communications as soon as practicable during an emergency on an onshore carbon dioxide pipeline. This proposal also requires operators to transmit additional messages to affected entities throughout the emergency as critical safety information is updated or the emergency in resolved. This proposal requires that these communications must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area. Finally, PHMSA proposes to require operators of onshore carbon dioxide pipelines to determine (based on population density survey data they collect to meet the proposed requirements at § 195.210 and § 195.402(c)(17)) if members of the public might require additional assistance and inform appropriate emergency responders of such needs during an emergency on an onshore carbon dioxide pipeline.

Lastly, PHMSA proposes to remove language at § 195.402(g) disclaiming application to carbon dioxide and hazardous liquid gathering lines of most of the amendments at § 195.402 (emergency planning, notification, and response provisions) that had been adopted in the Valve Rule but were subsequently vacated for gathering lines as a result of judicial review of that rulemaking, such that this provision would apply to non-rural gathering lines (§ 195.1(a)(4)(i)) and gathering lines located in inlets to the Gulf of Mexico (§ 195.1(a)(4)(iii)). PHMSA is not, however, proposing restoration of the Valve Rule's amendments to failure investigation requirements at § 195.402(c)(5) for any gathering lines.

§ 195.403 Emergency response training.

Section 195.403 requires all operators of part 195-regulated hazardous liquid and carbon dioxide pipelines to have training programs for emergency response personnel that may act in the event of a pipeline emergency. Subparagraph (a)(4) requires operators instruct emergency responders in the methods necessary to control any accidental release of hazardous liquid or carbon dioxide and the steps to minimize the potential for fire, explosion, toxicity, or environmental damage. This NPRM proposes to add that operators must also provide instruction on how the potential for asphyxiation should be minimized, in addition to the currently listed conditions.

§ 195.404 Maps and Records.

Section 195.404 requires operators to maintain maps and records of their pipeline systems, including pump stations. This NPRM proposes a conforming change at § 195.404 by adding "compressor stations" to the list of facilities requiring signage, consistent with the addition of the gas phase to the definition of carbon dioxide at § 195.2.

§ 195.406 Maximum operating pressure.

Section 195.406 defines the MOP at which part 195-regulated pipelines may operate. Paragraph (a)(5) defines the MOP for pipelines that meet specific exception requirements at § 195.302(b)(1) and (b)(2)(i). This NPRM proposes a conforming change at § 195.406 by modifying the reference to "(b)(2)(i)" to "(b)(2)." This change would result in adding newly excepted carbon dioxide pipelines to the list of pipelines for which MOP may be defined in accordance with § 195.406(a)(5).

§ 195.412 Inspection of rights-of-way and crossings under navigable waters.

Section 195.412 requires operators of all part 195-regulated hazardous liquid and carbon dioxide pipelines to perform recurring inspections of the pipeline right-of-way and navigable water crossings. At least 26 times each calendar year (at intervals not exceeding 3 weeks), the operator must inspect the surface conditions on or adjacent to the right-of-way, per § 195.412(a). These inspections can be performing by walking, driving, or flying the right-of-way, or other methods as appropriate for inspecting the right-of-way.

In this NPRM, PHMSA proposes modifications at § 195.412(a) and the addition of new paragraphs (c), (d), and (e). These proposals apply to all hazardous liquid and carbon dioxide pipelines. At paragraph (a), PHMSA proposes replacing "shall" with "must" for consistency with the majority of the language in part 195. PHMSA also proposes that the inspections required by § 195.412(a) must be performed for the surface conditions of the right-of-way and adjacent areas to the right-of-way. This is a modification from "or" to "and." Lastly, at paragraph (a), PHMSA proposes added language stating that these inspections must examine the surface conditions for "indications of leakage, construction activity, geologic hazards, reduced depth of cover, and other factors that may affect pipeline integrity, safety, and operation." This codifies guidance from PHMSA advisory bulletins and industry best practices.

PHMSA proposes the addition of § 195.412(c), which would require that when operators observe indications of geologic hazards on or adjacent to the right-of-way, they must perform certain preventative, mitigative, and remedial actions. PHMSA proposes the operator must: (1) perform additional inspections and evaluations, (2) determine the extent of geologic hazards and their impact on the pipeline, and (3) take remedial action, in accordance with § 195.401(b).

PHMSA proposes the addition of § 195.412(d), which would require that when operators observe indications of depth of cover less than required by § 195.248, they must perform certain preventative, mitigative, and remedial actions. PHMSA proposes the operator must: (1) perform additional inspections and evaluations, (2) determine the extent of the reduced depth of cover and its impact on the pipeline, and (3) take remedial action, in accordance with § 195.401(b).

PHMSA also proposes the addition of § 195.412(e), which would require that operators maintain, for the life of the pipeline, records of additional inspections, evaluations, determinations of need for remedial action, and remedial actions performed under paragraphs (c) and (d) of this section.

§ 195.417 Notification of potential rupture.

PHMSA adopted § 195.417 in the Valve Rule to codify commonly understood criteria for, or indicators of, a potential rupture. Consistent with the judicial review of that rulemaking, PHMSA subsequently introduced language disclaiming application of this provision to hazardous liquid gathering lines. PHMSA now proposes to remove that exception, such that this provision would apply to non-rural gathering lines (§ 195.1(a)(4)(i)) and gathering lines located in inlets to the Gulf of Mexico (§ 195.1(a)(4)(iii)).

§ 195.429 Maintenance and testing of fixed vapor detection and alarm systems.

In this NPRM, PHMSA proposes the addition of a new § 195.429. In this section, PHMSA proposes to require the maintenance and testing of fixed vapor detection and alarm systems on all part-195 regulated pipelines transporting HVLs wherever such systems are required by 195 to be installed (see §§ 195.263 and 195.452(i)(5)). The proposed maintenance and testing requirements consist of maintaining each fixed vapor detection and alarm system to function properly and performing testing of the system at least once per calendar year, but at intervals not exceeding 15 months. PHMSA proposes that the periodic testing of vapor detection and alarm systems be performed under conditions approximating actual operations and include tests of the individual components of the system and the entire system.

§ 195.434 Signs.

Section 195.434 requires signage at specific pipeline facilities, including pumping stations and breakout tank areas, and prescribes information that must be included on this signage. This NPRM proposes a conforming change at §195.434 by adding "compressor stations" to the list of facilities requiring signage, consistent with the addition of the gas phase to the definition of carbon dioxide at § 195.2.

§ 195.436 Security of facilities.

Section 195.436 requires operators to provide protection from vandalism of, and unauthorized entry to, various pipeline facilities, including pumping stations, breakout tank areas, and other exposed facilities. This NPRM proposes a conforming change at §195.436 by adding "compressor stations" to the list of facilities requiring protection from vandalism and unauthorized entry, consistent with the addition of the gas phase to the definition of carbon dioxide at § 195.2.

§ 195.438 Smoking or open flames.

Section 195.438 prohibits smoking and open flames in each pump station area and each breakout tank area where flammable hazardous liquids or flammable vapors may be present. While carbon dioxide is non-flammable, compressor units operating on pipelines transporting gas-phase carbon dioxide can be powered by combustible materials, such as natural gas. Thus, flammable vapors may be present at compressor stations on gas-phase carbon dioxide pipelines.

PHMSA proposes the addition of compressor stations to the list of areas where smoking and open flames are prohibited if flammable hazardous liquids or flammable vapors may be present.

§ 195.444 Leak detection.

Section 195.444 details the minimum requirements for a leak detection system in accordance with §195.134 and § 195.452(i)(3). Section 195.444 is applicable to pipelines transporting hazardous liquids without gas in the liquid and excludes offshore gathering or rural regulated gathering lines. As noted in the section-by-section analysis for §195.134, PHMSA proposes leak detection systems be required on all pipelines transporting carbon dioxide, and that these leak detection systems be CPM leak detection systems on supercritical- and liquid-phase carbon dioxide pipelines. Conforming changes to add carbon dioxide to paragraphs (a) and (c) are proposed at § 195.444 for consistency with those proposed changes at §195.134.

§ 195.450 Definitions.

Section 195.450 contains the definitions applicable to hazardous liquid and carbon dioxide pipeline segments that could affect or are in HCAs. The definitions are contained at § 195.450, but have applicability in the IM-related sections, specifically §§ 195.452, 195.454, and the new section proposed in this NPRM, § 195.456, and anywhere else they are referenced in part 195 (i.e., §§ 195.48, 195.260, 195.402 and 195.418). PHMSA is proposing to amend § 195.450 to make these definitions apply wherever they are used throughout part 195.

§ 195.452 Pipeline integrity management in high consequence areas.

Section 195.452 contains the requirements for an IM program for both hazardous liquid and carbon dioxide operators applicable to each pipeline segment that could affect an HCA. Paragraph (e) lists the minimum factors that an operator must consider when establishing an integrity assessment schedule. Among other requirements, paragraph (f) contains the minimum elements of a written IM program, including a process for identifying which pipeline segments could affect an HCA. Paragraph (i) requires operators to take specific measures to prevent and mitigate the consequences of a pipeline failure that could affect an HCA. When identifying the need for additional preventive and mitigative measures, an operator must evaluate the likelihood of a pipeline release occurring and how a release could affect HCAs. Subparagraph (i)(2) and its subparagraphs require the operator to consider all relevant risk factors when making this determination, including the surrounding terrain, characteristics of the transported product, and amount of possible released product, among others. Subparagraph (i)(4) requires operators to determine if an EFRD is needed in the event of a hazardous liquid release in an HCA or an area that could affect an HCA.

PHMSA proposes several revisions to the IM requirements at § 195.452. First, PHMSA proposes to modify each of the list of risk factors (§ 195.452(e)(1)(iv)) meriting consideration when establishing IM assessment schedules and the analysis criteria employed in taking preventative and mitigative actions (§ 195.452(i)(2)(iii)) to add a reference to "deleterious constituents such as hydrogen sulfide and water" alongside existing text requiring hazardous liquid and carbon dioxide pipeline operators to consider the product transported. Second, PHMSA proposes to amend § 195.452(f)(1) to explicitly require that all HVL pipelines (including carbon dioxide pipelines) perform vapor dispersion analyses when evaluating which of their pipeline segments could affect an HCA and would therefore be subject to part 195 IM program requirements. Third, PHMSA proposes to amend § 195.452(i)(4) to extend to all carbon dioxide pipelines the existing requirement for EFRD installation (as required by an operator's IM program) to protect HCAs. Finally, PHMSA proposes to add a new paragraph at § 195.452(i)(5) to require operators of existing pipelines transporting an HVL (including carbon dioxide) to have fixed vapor detection and alarm systems meeting the requirements of proposed § 195.263, at each pump station, compressor station, meter station, and valve station (including facilities for launching and receiving ILI tools or instrumented internal inspection devices) that are located in or could affect an HCA. PHMSA also proposes a conforming change at § 195.452(i)(1) to reflect the addition of § 195.452(i)(5).

§ 195.456 Vapor dispersion analysis.

PHMSA proposes the addition of a new § 195.456 with specific requirements for performance of vapor dispersion analyses by HVL pipelines, including carbon dioxide pipelines. Among the proposed requirements are those pertaining to the minimum required elements and factors evaluated in those analyses (including the physical characteristics of the transported product; operating conditions and system design of the pipeline; nearby terrain, vegetation, and manmade structures that could influence potential physical pathways between the pipeline and the HCAs; and weather conditions); operator obligations regarding updating their analyses to reflect improved software models; and documentation requirements.

PHMSA also proposes that, in lieu of performing vapor dispersion modeling, an operator of an HVL pipeline would be able to satisfy § 195.456 by using a default assumption that a release could affect all HCAs within 2 miles on either side of the pipeline.

§ 195.579 What must I do to mitigate internal corrosion?

Section 195.579 prescribes what actions operators of part 195-regulated pipelines must take to mitigate internal corrosion, including the use of inhibitors and inspection of the internal surface of removed pipe. In this section, PHMSA proposes a new paragraph (e) to require carbon dioxide pipeline operators to develop and implement a monitoring and mitigation program capable of mitigating corrosion-affecting constituents in the product stream, including but not limited to, water, oxygen, methane, hydrogen sulfide, carbon monoxide, sulfur oxides, and nitrogen oxides. Pipelines that are constructed, replaced, relocated, otherwise changed, or converted must implement this program to monitor and mitigate the effects of those constituents that may cause internal corrosion to the pipeline prior to placing the pipeline into service. Pipelines that are currently in service on the effective date of the rule would have 12 months to meet the requirements of this new paragraph. PHMSA's proposed new paragraph (e) would also require operators to allow no free water and otherwise limit the amount of water to no more than 50 ppm by volume of the total product stream in any phase of carbon dioxide. Additionally, PHMSA proposes to limit the amount of hydrogen sulfide that may be present in the product stream to less than 20 ppm by volume of the total product stream in any phase of carbon dioxide. PHMSA also proposes to require operators to periodically evaluate if the corrosion-affecting constituents are effectively monitored and mitigated (quarterly) and to evaluate and review the monitoring and mitigation program to perform updates and make necessary adjustments (annually). Finally, PHMSA proposes to revise the title of § 195.579 and language at paragraphs (a) through (d) to reflect modern language usage without substantive change to those provisions.

§ 195.588 Direct assessment standards.

Section 195.588 states the requirements for direct assessment on both carbon dioxide and hazardous liquid pipelines. When operators opt to complete a spike hydrostatic pressure test when performing the remediation required by § 195.588(c)(4), they must follow the requirements at § 195.588(c)(4)(ii). In this NPRM, PHMSA proposes the addition of § 195.309 under subpart E for spike hydrostatic testing requirements. PHMSA proposes a conforming change at § 195.588(c)(4)(ii) to remove the specifics of the spike hydrostatic pressure test requirements from that section and instead require spike hydrostatic pressure tests performed under § 195.588 comply with § 195.309.

PHMSA also proposes a typographical correction at § 195.588(c)(4)(i) to correct a paragraph reference that should point to paragraph (c)(4)(ii) of § 195.588 instead of paragraph (b)(4)(ii). In addition, PHMSA proposes a change to the title of § 195.588 to refer to the section content without doing so in the form of a question.

Appendix B to Part 195—Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines

Appendix B to Part 195, "Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines," provides guidance on the risk-based alternative to pressure testing older hazardous liquid and carbon dioxide pipelines that is allowed by § 195.303. Appendix B to Part 195 establishes test priorities based on the inherent risk of a given pipeline segment for older pipelines that were not previously pressure tested. Table 4 of Appendix B to Part 195, "Product Indicators," provides risk classifications based on the product transported. These classifications are based on the degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and volatility, flammability, and water solubility. Appendix B to Part 195 can be used by operators of hazardous liquid and carbon dioxide pipelines alike.

PHMSA proposes adding an additional category of products under the medium risk-indicator in table 4 of Appendix B to Part 195: asphyxiating. PHMSA proposes adding carbon dioxide as the sole example of a product meeting this category. PHMSA also proposes removing the final category under the risk indicator of low (highly volatile and non-flammable/non-toxic) to conform with this change.

Appendix C to Part 195—Guidance for Implementation of an Integrity Management Program

Appendix C to Part 195, "Guidance for Implementation of an Integrity Management Program," provides guidance to help part 195 operators implement the IM requirements. Section I. of Appendix C to Part 195 provides guidance on identifying HCAs and factors for considering a pipeline segment's potential impact on an HCA. Section III. of Appendix C to Part 195 contains safety risk indicator tables for leak history, volume or line size, age of pipeline, and product transported. Appendix C to Part 195 can be used by operators of hazardous liquid and carbon dioxide pipelines alike.

PHMSA proposes adding an additional category of products under the medium risk-indicator in the "Product Transported" table of Appendix C to Part 195: asphyxiating. PHMSA proposes adding carbon dioxide as the sole example of a product meeting this category.

In this NPRM, PHMSA has proposed modifying the definition of HVL to include carbon dioxide. As a conforming change with this proposal, PHMSA proposes adding a parenthetical after HVL at I.B.(5) of Appendix C to Part 195 to note that carbon dioxide is included within the proposed definition of HVL.

§ 196.109—What must an excavator do if damage to a pipeline from excavation activity causes a leak where product is released from the pipeline?

This provision identifies actions that excavators must take in response to a release on parts 192, 193, or 195-regulated pipeline facilities caused by excavation activity. PHMSA proposes a clarifying revision at paragraph (d) to explicitly mention releases from hazardous liquid pipelines transporting carbon dioxide alongside releases of other products from hazardous liquid pipelines.

§ 198.3—Definitions.

This provision contains definitions for regulatory language used in part 198 governing grants to aid State pipeline safety programs. PHMSA proposes to amend the definition of "underground pipeline facilities" to communicate more clearly that hazardous liquid pipelines transporting carbon dioxide are among those hazardous liquid pipeline facilities which are addressed by this part.

§ 198.55—What criteria will PHMSA use in evaluating the effectiveness of State damage prevention enforcement programs?

This provision identifies the criteria PHMSA uses for evaluations of the effectiveness of State damage prevention enforcement programs, including whether those programs include reporting requirements for excavators who cause damage(s) resulting in product release. PHMSA proposes a clarifying revision of language at § 198.55(a)(6)(iii)(B) to explicitly mention releases from carbon dioxide pipelines alongside releases of other products from hazardous liquid pipelines.

V. Regulatory Analyses and Notices

A. Legal 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 Laws (49 U.S.C. 60101 et seq.). Section 60102 grants authority to issue standards for the pipeline transportation of hazardous liquids and carbon dioxide to protect public safety and the environment by imposing minimum requirements for the design, installation, inspection, emergency plans and procedures, testing, construction, extension, operation, replacement, and maintenance of those pipeline facilities and the qualification of personnel operating those facilities. 49 U.S.C. 60102(b)(5) specifies that PHMSA must consider both public safety and environmental benefits when issuing any such standards. Additionally, the Pipeline Safety Laws direct PHMSA to establish requirements for public outreach and awareness (49 U.S.C. 60116) and IM (49 U.S.C. 60109) programs of those operators.

As explained in greater detail in Section II.C above, this NPRM proposes a series of regulatory changes which implement Congressional amendments (first in 1988 and subsequently expanded in 2011, each codified at 49 U.S.C. 60102(i)) authorizing PHMSA to use its part 195 regulatory regime to regulate transportation within hazardous liquid pipelines of carbon dioxide in any phase. Further, 49 U.S.C. 60117 authorizes PHMSA to direct operators of those pipeline facilities to submit reports and records to PHMSA to inform its regulatory oversight activities; similarly, other provisions of the Pipeline Safety Laws authorize PHMSA to require safety condition reports (49 U.S.C. 60102(h)) and NPMS data (49 U.S.C. 60132) among those submissions. Likewise, PHMSA's proposed extension of its part 195 regulatory regime to include new compositions and physical states of carbon dioxide transported in hazardous liquid pipelines also implicates its statutory authority (49 U.S.C. 60301) to impose user fees in connection with pipelines newly subject to the PSR.

B. Executive Order 12866 and DOT Regulatory Policies and Procedures

E.O. 12866, as amended by E.O. 14094, requires that agencies "should assess all costs and benefits of available regulatory alternatives, including the alternative of not regulating."[290] Agencies should consider quantifiable measures and qualitative measures of costs and benefits that are difficult to quantify. Further, E.O. 12866 requires that agencies should select those regulatory approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributional 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.

E.O. 12866 (as amended) and DOT Order 2100.6A require that PHMSA submit "significant regulatory actions" to the Office of Management and Budget (OMB) for review. This proposed rule has been determined to be significant under section 3(f) of E.O. 12866. It is also considered significant under DOT Order 2100.6A because of significant congressional, State, industry, and public interest in pipeline safety. The proposed rule has been reviewed by OMB in accordance with E.O. 12866 (as amended) and is consistent with the requirements of E.O. 12866 (as amended) and DOT Order 2100.6A.

[290] 58 FR 51735 (Oct. 4, 1993).

E.O. 12866 (as amended) and DOT Order 2100.6A also require PHMSA to provide a meaningful opportunity for public participation, which reinforces requirements for notice and comment in the Administrative Procedure Act (APA, 5 U.S.C. 551 et seq.). In accord with the requirement, PHMSA seeks public comment on the proposals in the NPRM (including preliminary cost and cost savings analyses pertaining to those proposals set forth in the PRIA, as well as discussions of the public safety, environmental, and equity benefits in that document and the DEA), as well as any information that could assist in evaluating the benefits and costs of PHMSA's NPRM.

Consistent with E.O. 12866 (as amended) 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 accidents on carbon dioxide and other part 195-regulated hazardous liquid pipeline facilities. PHMSA invites commenters to provide additional information that would enable quantification of the additional health and safety benefits of the rule.

PHMSA estimates the annualized costs of $21.3 million per year (using a 2 percent discount rate). For the full cost/benefit analysis, please see the PRIA in the rulemaking docket.

C. Environmental Justice

E.O. 12898 ("Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations"),[291] and E.O. 14096 ("Revitalizing Our Nation's Commitment to

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[291] 59 FR 7629 (Feb. 16, 1994).

Environmental Justice for All")[292] direct Federal agencies to make achieving environmental justice part of their mission consistent with statutory authority by identifying, analyzing, and addressing disproportionate and adverse human health and environmental effects and hazards of Federal activities, including those related to climate change and cumulative impacts of environmental and other burdens on communities with environmental justice concerns.

PHMSA has evaluated this NPRM and has preliminarily determined it will not cause disproportionate and adverse human health and environmental effects on communities with environmental justice concerns. 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 expects the rulemaking will reduce the safety and environmental risks associated with losses of integrity on pipeline facilities transporting hazardous liquids and carbon dioxide in supercritical, liquid, and gas phases, which will advance public health and safety protection for all affected communities. Further, as explained in the DEA in the rulemaking docket, PHMSA expects that the regulatory amendments in this proposed rule will reduce emissions of carbon dioxide (a GHG) from pipeline facilities, thereby reducing the risks posed by anthropogenic climate change to the public, including communities with environmental justice concerns.

Finally, DOT anticipates that this proposed rule would help to advance several goals consistent with E.O. 14096 and DOT's environmental justice policies, including continuing to

[292] 88 FR 25251 (April 26, 2023).

deepen the Biden-Harris Administration's whole-of-government approach to environmental justice and to better protect overburdened 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 (codified at 5 U.S.C. 601 *et seq.*), generally requires Federal regulatory agencies to prepare an initial regulatory flexibility analysis (IRFA) for a rule subject to notice-and-comment rulemaking under the Administrative Procedures Act (APA) 5 U.S.C. 603(a).[293] E.O. 13272 ("Proper Consideration of Small Entities in Agency Rulemaking")[294] requires agencies to establish procedures promoting compliance with the Regulatory Flexibility Act. DOT's implementing guidance is available on its website.[295] This NPRM was developed in accordance with E.O. 13272 and DOT guidance to promote compliance with the Regulatory Flexibility Act and to ensure that the potential impacts of the rulemaking on small entities have been properly considered. PHMSA seeks comment on whether the proposed rule, if adopted, would have a significant economic impact on a significant number of small entities. For more information, see the IRFA in section 9 of the PRIA.

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

[293] 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.
[294] 67 FR 53461 (Aug. 16, 2002).
[295] DOT, "Rulemaking Requirements Related to Small Entities," https://www.transportation.gov/regulations/rulemaking-requirements-concerning-small-entities (last updated May 18, 2012).

PHMSA analyzed privately owned entities that could be impacted by the rule, which includes operators of pipelines transporting carbon dioxide or HVLs and gathering lines transporting hazardous liquids located in non-rural areas or inlets to the Gulf of Mexico (GOM). PHMSA determined whether these entities were small entities based on the size of the parent entity and using the relevant SBA (Small Business Administration) size standards, as set out in Appendix C of the PRIA. Specifically, PHMSA relied on SBA's current size threshold guidelines in effect as of March 17, 2023, which provide threshold number of employees or revenue for each relevant North American Industry Classification System (NAICS) sector to determine small business status. 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 populations less than 50,000 are considered small. PHMSA did not identify any municipal or other government entities that own carbon dioxide or affected hazardous liquid pipeline systems and does not anticipate that government entities will own these types of pipelines in the future.[296] A portion of small entities' compliance costs may be offset by the Federal tax incentives discussed in Section 3.2. of the PRIA. As a result, this analysis may overestimate the overall economic impact of the proposed rule on regulated entities. In 2022, 13 of the 29 carbon dioxide pipeline operators (45 percent), 82 of the 177 HVL pipeline operators

[296] The locations where carbon capture would be performed (and the end use sites and sequestration sites where carbon would be used and stored) are unlikely to be owned by government entities and/or in the same location as government jurisdictions. Additionally, these pipeline projects are capital-intensive in nature, and are therefore more likely to be undertaken by commercial entities.

(46 percent), and 58 of the 85 operators of gathering lines transporting hazardous liquids located in non-rural areas or inlets to the GOM (68 percent) were small entities.[297]

Lacking information on how these percentages may change in the future, PHMSA assumed for the purposes of the IRFA analysis that they will remain the same over the 20-year timeframe of the analysis. PHMSA applied these percentages to the projected number of operators and determined the number of small businesses that would be affected by the proposed rule: 66 small carbon dioxide pipeline operators, 48 small HVL pipeline operators, and 20 small operators of gathering lines transporting hazardous liquids located in non-rural areas or inlets to the GOM.

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

PHMSA analyzed the costs of compliance for carbon dioxide pipeline operators, HVL pipeline operators, and operators of gathering lines transporting hazardous liquids located in non-rural areas or inlets to the GOM and estimated the annual per operator cost by dividing the total annualized costs of the proposed rule by the number of projected operators in 2043. Per operator cost of $120,000 was calculated for carbon dioxide pipeline operators by dividing the estimated annualized cost of the proposed rule ($21.2 million at 2 percent discount rate) by the projected

[297] PHMSA was unable to identify NAICS codes for 6 parent companies of operators of pipelines transporting HVLs. However, PHMSA did identify revenue and employment information for 5 of these entities; revenue and employment information for these entities fall below all of SBA's revenue and employment thresholds. Therefore, PHMSA assumed they are small businesses. PHMSA was unable to identify the NAICS code and revenue and employment information for one of these 6 companies, but assumed it is a small business.

number of operators (176) in 2043. Per operator cost of approximately $40 for HVL pipeline operators was calculated by dividing estimated annualized cost of the proposed rule ($11,000 at 2 percent discount rate) by the projected number of operators (282) in 2043. Per operator cost of approximately $800 for operators of gathering lines transporting hazardous liquids located in non-rural areas or inlets to the GOM were calculated by dividing estimated annualized cost of the proposed rule ($91,000 at 2 percent discount rate) by the projected number of operators (115) in 2043. In cases where a parent company owned multiple operators, PHMSA summed the compliance costs across these operators to compare to the parent company's revenue.[298]

PHMSA then calculated cost-to-revenue (CTR) ratios using the calculated compliance costs of each small parent entity. For 46 percent of the small businesses that owned carbon dioxide pipelines in 2022, the compliance costs of the proposed rule represent one percent or more of annual revenues. For 31 percent of the small entities that owned carbon dioxide pipelines in 2022, the compliance costs of the proposed rule represent more than 3 percent of annual revenues. For 100 percent of small entities that owned HVL pipelines in 2022, the compliance costs of the proposed rule are estimated to be less than 1 percent of annual revenues.[299] For 100 percent of small entities that owned gathering lines transporting hazardous liquids located in non-rural areas or inlets to the GOM in 2022, compliance costs of the proposed rule represent less than one percent of annual revenues.

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[298] A portion of small entities' compliance costs may be offset by the Federal tax incentives discussed in Section 3.2.
[299] PHMSA was unable to find revenue information for one of these small entities that owns an HVL pipeline and therefore did not include it in the CTR test. However, PHMSA assumes that it is a small entity in the extrapolation of results for HVL pipeline operators.

Lacking data on how revenues of future small operators may change from those of current operators, PHMSA extrapolated the results of the CTR tests conducted on the current carbon dioxide and HVL operators to the projected future operators. Thus, PHMSA assumed that 54 percent of future carbon dioxide operators that are small businesses (36 entities) would incur costs less than one percent of total revenue, 15 percent (10 entities) would incur costs between one and three percent of total revenue, and 31 percent (20 entities) would incur costs greater than three percent of total revenue. As the market for CCUS evolves, however, it is very likely that the share of larger companies entering the market will increase, as well as due to mergers and acquisitions of current small operators to consolidate operations. PHMSA used the number of projected operators of HVL pipelines (282) and assumed that 46 percent (the current percentage of small operators plus approximately half of operators with unknown small business status) will be small entities. Excluding the 177 known operators identified using 2022 annual report data, and applying a rate of 46 percent, this results in an estimated 48 additional small entity operators over the analysis period. PHMSA then extrapolated the results of the CTR test to the projected 48 small entities. PHMSA assumed 100 percent of small entities would incur costs less than one percent of total revenue. PHMSA used the same approach described above to extrapolate the results of the CTR test to the projected number of operators of gathering lines transporting hazardous liquids located in non-rural areas or inlets to the GOM (115). PHMSA assumed that 100 percent (20 operators) of future gathering lines transporting hazardous liquids located in non-rural areas or inlets to the GOM that are small businesses would incur costs less than one percent of total revenue, and none would incur costs greater than one percent of total revenue. The main sources of uncertainty in this analysis are described in Section 9.3 in the PRIA.

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. PHMSA covers the relationship between the proposed rule and other relevant Federal and State regulations in the NPRM.

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 2.2 of the PRIA. In addition to retaining the status quo and not issuing the proposal, which PHMSA determined would fail to satisfy congressional mandates to improve safety and update PHMSA regulations, PHMSA developed the proposed rule to minimize and mitigate potential impact on small entities, including: flexibility for operators when choosing methods to meet the proposed requirements for fracture control and arrest; an alternate option of 2 miles as the standard distance when determining which pipeline segments could affect an HCA, which can significantly decrease costs from vapor dispersion modelling; and the use of preexisting operator systems for public awareness to perform the proposed public notifications in the event of an emergency. PHMSA did not identify significant alternatives to the proposed rule that would serve in the interest of public safety while minimizing the economic impact of the proposed rule on small entities.

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 E.O. 13175 ("Consultation and Coordination with Indian Tribal Governments")[300] and DOT Order 5301.1A ("Department of Transportation Tribal Consultation Policy and Procedures"). E.O. 13175 requires agencies to ensure meaningful and timely input from Tribal government representatives in the development of rules that "have substantial direct effects on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes," has "substantial direct compliance costs on Indian tribal governments" or "preempts tribal law."

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, much less impose substantial compliance costs on Tribal governments or mandate Tribal action. Insofar as PHMSA expects the NPRM will improve safety and reduce environmental risks associated with hazardous liquid and carbon dioxide pipelines, PHMSA expects it will not entail disproportionate adverse risks for Tribal communities. While PHMSA is not aware of specific Tribal-owned business entities that currently operate, or plan to operate, carbon dioxide pipelines, any such business entities could be subject to direct compliance costs as a result of this proposed rule. Therefore, the funding and consultation requirements of E.O. 13175 and DOT Order 5301.1A therefore do not apply. PHMSA seeks comment on the applicability of E.O.

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[300] 65 FR 67249 (Nov. 6, 2000).

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. Some of the proposals in the Pipeline Safety: Safety of Carbon Dioxide and Hazardous Liquid Pipelines NPRM will trigger new or amended reporting, notification, and recordkeeping requirements for operators of gas-, liquid-, and supercritical-phase carbon dioxide pipelines, as well as hazardous liquid pipelines.

Operator Registry and Notification Requirements

PHMSA estimates two newly regulated carbon dioxide operators would become subject to the reporting and recordkeeping requirements of 49 CFR part 195. As such, these operators will be required under § 195.65 to obtain an Operator ID (OPID) number and make required notifications. PHMSA currently estimates that it takes operators 1 hour to request an OPID by submitting form PHMSA F 1000.1. Similarly, PHMSA estimates that it takes operators 1 hour to make required notifications by submitting form PHMSA F 1000.2. The burden for this information collection will be adjusted to include the burden on the two newly regulated carbon dioxide operators to obtain and OPID and to make notifications, if needed.

Annual Reporting

Pursuant to the proposed § 195.49, PHMSA requires pipeline operators to submit data on the phase description for carbon dioxide, the total number of leaks involving carbon dioxide, and the total volume of carbon dioxide released in a calendar year. To collect this data, PHMSA proposes to revise form PHMSA F 7000-1.1, the Annual Report for Hazardous Liquid and Carbon Dioxide Pipeline Systems. PHMSA estimates that approximately 475 operators spend 20 hours, annually, completing this report for an overall annual burden of 9,500 hours. PHMSA estimates three newly regulated operators of carbon dioxide pipeline systems will be subject to these reporting requirements, with each new operator spending 20 hours, annually, submitting annual report data. Accordingly, PHMSA expects the burden on operators to complete form PHMSA F 7000-1.1, Annual Report for Hazardous Liquid and Carbon Dioxide Pipeline Systems, to increase by three responses and 60 hours.

Operators of supercritical-, gas-, and liquid-phase carbon dioxide pipeline systems would be required to submit data on the number and type of leaks occurring during a calendar year. PHMSA estimates 23 operators will need to submit this data via the annual report. PHMSA estimates operators would spend 10 hours submitting this data in the first year and then 5 hours in the subsequent years. As a result, PHMSA expects the overall burden for operators to submit data on carbon dioxide leaks to be 23 responses and approximately 154 hours annually.

Accident Reporting

Pursuant to the proposed § 195.54, PHMSA requires pipeline operators to submit data on the phase description for the carbon dioxide released during a reportable accident. Operators will be required to indicate whether the carbon dioxide released was in the gas, liquid, or supercritical phase. To collect this data, PHMSA proposes to revise form PHMSA F 7000-1, Accident Report – Hazardous Liquid and Carbon Dioxide Systems, to include the required phase descriptions. PHMSA expects this to be a minor addition to the currently approved hazardous liquid accident report, and therefore expects the currently approved burden estimate for reporting accident data to be sufficient for providing this information.

Additionally, operators of carbon dioxide pipeline systems are required to notify the National Response Center (NRC) in the instance of a reportable accident. PHMSA expects the burden for notifying the NRC to increase by one response and 0.5 hours annually for operators of carbon dioxide pipeline systems.

Record Keeping Requirements

The proposed rule requires operators of carbon dioxide pipeline systems to make and maintain various records. Newly regulated operators of carbon dioxide pipeline systems will be subject to all applicable recordkeeping requirements in 49 CFR parts 195 and 199 for drug and alcohol programs.

In accordance with § 195.5(f), operators converting a steel pipeline to carbon dioxide service are required to keep records of investigations, test, repairs, replacements, and alterations associated with this task. PHMSA expects one operator each year to spend 20 hours complying with this requirement.

Pipeline rights-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. No pipeline may be located within 50 feet (15 meters) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, unless it is provided with at least 12 inches (305 millimeters) of cover in addition to that prescribed at § 195.248. The newly proposed § 195.210(c)(i) requires operators to maintain records for the life of the pipeline as to why locations within two miles of any residence, or any business or place of public assembly in which persons work, congregate, or assemble were impracticable to avoid. PHMSA expects 39 operators to spend 1 hour annually maintaining these records.

Section 195.310 requires operators to keep records of pressure tests for the life of the pipeline. PHMSA estimates that two new or converted carbon dioxide pipeline operators will spend 20 hours each complying with this requirement annually.

Section 195.402(a) requires pipeline operators to prepare and follow a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies for each pipeline system. PHMSA expects two newly regulated carbon dioxide pipeline operators to spend 100 hours annually, each, developing this manual of written procedures. Similarly, § 195.402(a) requires an annual review of these records. PHMSA estimates that one operator will spend 70 hours each year reviewing their operations and maintenance procedures.

Section 195.456(d) requires operators of carbon dioxide pipeline systems to make and maintain records of vapor dispersion analyses conducted on their systems. PHMSA expects 16 carbon dioxide pipeline operators to spend 1 hour, each, conducting this task.

Section 195.507 requires pipeline operators to maintain records regarding the qualification of pipeline personnel. Qualification records shall include identification of qualified individual(s), identification of the covered tasks the individual is qualified to perform, date(s) of current qualification, and the qualification methods used. PHMSA estimates three new operators of carbon dioxide pipeline systems will have an average of 569 covered employees. PHMSA expects each operator will spend 15 minutes, per covered employee, maintaining the required operator qualification records.

Section 195.589 requires pipeline operators to maintain records and maps pertaining to their corrosion control efforts. PHMSA estimates that three carbon dioxide operators will spend 1 hour each, annually, maintaining these records.

Operators must develop, implement, and follow a written integrity management program that addresses risks and describes plan to carry out baseline assessments in accordance with § 195.452(l). PHMSA expects an average of two new and converted carbon dioxide operators to spend 2,440 hours one time to develop this integrity management plan. PHMSA expects each year, one of these operators will spend 260 hours reviewing the plan and making updates as needed. Accordingly, PHMSA expects the burden for compliance to be three new responses and 5,140 hours.

Operators must also develop and implement a monitoring and mitigation program in accordance with § 195.579(e). PHMSA estimates 17 operators will spend 88 hours, one time, developing a monitoring and mitigation program. PHMSA estimates that 34 operators will spend 52 hours, annually, reviewing and updating these programs. PHMSA expects these additional recordkeeping requirements to result in an increased one-time burden of 51 responses and 3,264 hours for recordkeeping compliance.

Safety-Related Condition Reporting

Pursuant to the proposed § 195.55, PHMSA requires operators who transport HVLs, including carbon dioxide, to report on safety related conditions on all lines regardless of distance. Because of this change, PHMSA expects to receive approximately 21 more safety-related condition reports, annually. Accordingly, the burden for this information collection will increase by 21 responses and 126 hours annually.

National Pipeline Mapping System Reporting

Pursuant to § 195.61, pipeline operators are required to submit geospatial data, annually, to NPMS. Section 195.59 encourages operators to use NPMS to report the abandonment or deactivation of pipelines. PHMSA estimates that three newly regulated carbon dioxide operators would be subject to NPMS reporting with an estimated annual burden increase of 361 hours. PHMSA is revising this information collection to account for the burden on newly affected operators to submit geospatial data for carbon dioxide pipelines.

Notification Requirements

Pursuant to the proposed § 195.5(d)(i), PHMSA requires operators to make notifications, in accordance with § 195.18, 90 days in advance of using an alternative technology to perform the pipeline coating surveys required when converting a pipeline to part 195 service. Operators may proceed only if they do not receive a letter objecting to the proposed use of other technology and/or methods. PHMSA expects most operators to use the standard method of performing these surveys and therefore expects only 10 percent of operators to make these notifications.

Pursuant to the proposed § 195.402(e)(9), PHMSA requires operators to notify the affected public, as soon as practicable, during an emergency on a carbon dioxide pipeline in consultation with applicable local, county, State, regional, Federal, and tribal emergency response officials. Operators are required to make the notifications in accordance with the applicable communication requirements of § 195.440. In line with the estimated number of pipeline accidents involving carbon dioxide, PHMSA estimates one of these notifications would be made annually. PHMSA estimates that it would take operators 2 hours, per accident, to make these notifications.

Pursuant to the proposed § 195.111(b)(2), PHMSA requires operators who choose to use correction factors other than those specified in API Specification 5L, which is incorporated by reference into the PSR, to notify PHMSA in accordance with § 195.18. PHMSA expects most operators to use the correction factors stipulated in API Specification 5L, and therefore expects only 10 percent of operators (approx. 23) to spend 1 hour each making these notifications.

PHMSA will submit the following information collection requests to OMB for approval based on the requirements in this proposed rule. These information collections are contained in the pipeline safety regulations, 49 CFR parts 190 through 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 estimated burden for the following information collections is to be revised as follows:

1. Title: National Registry of Pipeline and Liquefied Natural Gas (LNG) Operators.

   OMB Control Number: 2137-0627.

   Current Expiration Date: 3/31/2025.

   Type of Request: Revision.

   Abstract: The National Registry of Pipeline and LNG Operators serves as the storehouse for the reporting requirements for an operator regulated or subject to reporting requirements under 49 CFR parts 192, 193, or 195. This registry incorporates the use of two forms: OPID Assignment Request (PHMSA F 1000.1) and National Registry Notification (PHMSA F 1000.2).

Affected Public: Operators of Pipeline Facilities.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 748.

Total Annual Burden Hours: 748.

Frequency of Collection: On occasion.

2. Title: Hazardous Liquid Pipeline Operator Annual Reports.

OMB Control Number: 2137-0614.

Current Expiration Date: 03/31/2026.

Abstract: The Federal PSR at 49 CFR 195.58 requires operators of hazardous liquid pipelines to submit specific data on the safety of their pipelines annually. This mandatory information collection requires the operators to submit data on the preceding year electronically by March 15th of each calendar year. This information is used by PHMSA to identify trends in hazardous liquid pipeline accidents and to identify operators who have poor safety records. The Pipeline Safety: Safety of Carbon Dioxide and Hazardous Liquid Pipelines NPRM requires pipeline operators to submit data on the phase description for carbon dioxide, the total number of leaks involving carbon dioxide, and the total volume of carbon dioxide released in a calendar year.

PHMSA currently estimates that approximately 475 operators spend 20 hours, annually, completing this report for an overall annual burden of 9,500 hours. PHMSA expects operators to spend an additional 6 hours, per report, gathering and submitting the newly required information for an overall burden of 26 hours per report. PHMSA also estimates 37 newly regulated operators of carbon dioxide pipeline systems to be subject to these reporting requirements with each new operator spending 26 hours, annually, submitting annual report data. Accordingly, PHMSA expects the burden on operators to complete form PHMSA F 7000-1.1, Annual Report for Hazardous Liquid and Carbon Dioxide Pipeline Systems, to increase by 23 responses and 3,448 hours.

Affected Public: Operators of hazardous liquid and carbon dioxide pipelines.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 976.

Total Annual Burden Hours: 18,264.

Frequency of Collection: Annual.

3. Title: Transportation of Hazardous Liquids by Pipeline: Recordkeeping and Accident Reporting.

   OMB Control Number: 2137-0047.

   Current Expiration Date: 04/30/2026.

   Abstract: This mandatory information collection covers the recordkeeping requirements and the collection of accident data from operators of hazardous liquid and carbon dioxide pipelines. Part 195 requires hazardous liquid operators to file an accident report as soon as practicable, but not later than 30 days after discovery of the accident on form PHMSA F 7000-1 whenever there is a reportable accident. With respect to accidents involving carbon dioxide, PHMSA is revising this information collection to require operators to indicate whether the carbon dioxide released was in the gas, liquid, or supercritical phase. PHMSA currently expects to receive 406 accident reports, annually, from operators of hazardous liquid and/or carbon dioxide pipeline systems. Due to the inclusion of newly regulated carbon dioxide pipeline operators, PHMSA expects to receive one additional accident report annually. PHMSA estimates that operators will spend 12 hours, per accident, compiling and submitting accident report data to PHMSA via form PHMSA F 7000-1 or PHMSA F 7000-2. PHMSA believes that the current time estimated for this information collection is sufficient for affected operators to include the newly required information. The burden of this information collection is being revised to account for the burden on newly regulated operators to submit accident report data.

Section 195.52 requires operators of hazardous liquid and carbon dioxide pipeline systems to make immediate telephonic or online notice to the National Response Center (NRC) in the event of a reportable accident. PHMSA estimates each notification to take 30 minutes. Similar to the rate of accidents above, PHMSA expects newly regulated carbon dioxide operators to make one additional notice to the NRC. The burden of this information collection is being revised to account for the burden on newly regulated operators to make NRC notifications.

This information collection is also being revised to require operators of carbon dioxide pipelines to make and maintain certain records. In accordance with § 195.404, operators must maintain maps and records of the pipeline system with location and identification of facilities. Operators must maintain daily operating records for discharge pressure at pump stations for 3 years. Operators must develop, implement, and follow a written integrity management program that addresses risks and describes plan to carry out baseline assessments in accordance with § 195.452(l). Operators must also develop and implement a monitoring and mitigation program in accordance with § 195.579. PHMSA expects these additional recordkeeping requirements to result in an increased burden of 23 responses and 5,204 hours for recordkeeping compliance.

Affected Public: Operators of hazardous liquid and carbon dioxide pipeline facilities.

Annual Reporting and Recordkeeping Burden:

Estimated number of responses: 1,767.

Estimated annual burden hours: 62,711.

Frequency of Collection: On occasion.

4. Title: Reporting Safety-Related Conditions on Gas, Hazardous Liquid, and Carbon Dioxide Pipelines and Liquefied Natural Gas Facilities.

   OMB Control Number: 2137-0578.

   Current Expiration Date: 3/31/2026.

   Abstract: 9 U.S.C. 60102 requires each operator of a pipeline facility (except master meter operators) to submit to DOT a written report on any safety-related condition that causes or has caused a significant change or restriction in the operation of a pipeline facility or a condition that is a hazard to life, property, or the environment. PHMSA proposes to revise this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Safety of Carbon Dioxide and Hazardous Liquid Pipelines NPRM to require operators who transport highly volatile liquids, including carbon dioxide, to report on safety related conditions on all lines regardless of distance. PHMSA expects this change to result in an additional burden of three responses and 18 hours for this information collection.

Affected Public: All pipeline operators, including carbon dioxide pipeline operators.

Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 195.

Total Annual Burden Hours: 1,170.

Frequency of Collection: Annual.

5. Title: National Pipeline Mapping System Program.

   OMB Control Number: 2137-0596

   Expiration Date: 3/31/2026

   Type of Request: Revision of a previously approved information collection.

   Abstract: The Pipeline Safety Improvement Act of 2002 (Pub. L. 107–355), 49 U.S.C. 60132, "National Pipeline Mapping System," requires the operator of a pipeline facility (except distribution lines and gathering lines) to provide information to PHMSA. Each operator is required to submit geospatial data appropriate for use in NPMS or data in a format that can be readily converted to geospatial data; the name and address of the person with primary operational control (to be known as its operator), and a means for a member of the public to contact the operator for additional information about the pipeline facilities it operates. Operators will submit the requested data elements once and make annual updates to the data if necessary. These data elements strengthen the effectiveness of PHMSA's risk rankings and evaluations, which are used as a factor in determining pipeline inspection priority and frequency; allow for more effective assistance to emergency responders by providing them with a more reliable, complete data set of pipelines and facilities; and provide better support to PHMSA's inspectors by providing more accurate pipeline locations and additional pipeline-related geospatial data that can be linked to tabular data in PHMSA's inspection database.

PHMSA proposes to revise this information in conjunction with proposed regulatory changes made in the Pipeline Safety: Safety of Carbon Dioxide and Hazardous Liquid Pipelines NPRM to account for the burden on newly affected operators to submit geospatial data for carbon dioxide pipelines. This also includes the use of the NPMS to submit data on abandoned or deactivated carbon dioxide pipelines. This addition will increase the number of responses for this information collection by 23 and increase the overall reporting burden by 2,760 hours.

Respondents: Operators of gas transmission, hazardous liquid, and carbon dioxide pipelines, and liquefied natural gas pipeline facilities.

Annual Reporting and Recordkeeping Burden:

Estimated Number of Responses: 1,369.

Estimated Total Annual Burden: 164,968.

Frequency of Collection: Annually.

6. Title: Hazardous Liquid Operator Notifications.

   OMB Control Number: 2137-0630

   Current Expiration Date: 3/31/2026.

   Abstract: A person owning or operating a pipeline facility is required to provide information to the Secretary of Transportation at the Secretary's request according to 49 U.S.C. 60117. The PSR contained within 49 CFR part 195 requires operators of hazardous liquid pipelines, including carbon dioxide pipelines, to make notifications upon the occurrence of certain events. These mandatory notifications help PHMSA to stay abreast of issues related to the health and safety of the nation's pipeline infrastructure.

   The proposed provisions in this rule include notification requirements for operators who utilize alternative or expanded technologies and methods when conducting pipeline coating surveys tied to conversion of service. Also included is the requirement for operators to notify the public and required public officials in the event of an emergency involving carbon dioxide pipelines. These notification requirements are necessary to ensure safe operation of pipelines and ascertain compliance with the pipeline safety regulations.

   Affected Public: Hazardous Liquid and Carbon dioxide pipeline operators.

   Annual Reporting and Recordkeeping Burden:

Total Annual Responses: 157.

Total Annual Burden Hours: 174.

Frequency of Collection: On occasion.

7. Title: Qualification of Pipeline Safety Training.

   OMB Control Number: 2137-0600

   Current Expiration Date: 4/30/2025.

   Abstract: 49 CFR part 192 subpart N and part 195 subpart G require all individuals who operate and maintain pipeline facilities to be qualified and keep records of qualification. The purpose of this mandatory information collection request is to ensure compliance with the record keeping requirements prescribed in the federal PSR. Pipeline operators must make and maintain the records as described and have those records available for compliance inspection by PHMSA staff upon request. Examples of such records include the identification of qualified individuals; identification of covered tasks; dates of current qualification; and qualification methods. Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of five years.

   Affected Public: Pipeline Operators.

   Annual Reporting and Recordkeeping Burden:

   Total Annual Responses: 29,175.

   Total Annual Burden Hours: 7,435.

Frequency of Collection: On occasion.

Requests for copies of these information collections should be directed to Angela Hill at angela.hill@dot.gov. 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; and

(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.

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, N.W., Washington, D.C. 20503. Comments should be submitted on or prior **to [INSERT DATE 60 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

G. Unfunded Mandates Reform Act of 1995

The Unfunded Mandates Reform Act (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 in the Unfunded Mandates Reform Act to prepare a statement 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 consider and disclose the environmental impacts of major Federal actions. The Council on Environmental Quality's implementing regulations (40 CFR parts 1500-1508) require Federal agencies to prepare 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 prepared a DEA considering the likely environmental impacts of the proposed rule. That analysis concludes that the proposed rule will not have a significant impact on the human or natural environment and so does not require analysis in an Environmental Impact Statement. PHMSA's DEA finds that, to the extent that the proposed rule could impact the environment, those impacts will be primarily beneficial impacts from reducing the likelihood and consequences of accidents on carbon dioxide pipelines and other part 195-regulated hazardous liquid pipelines. A copy of the DEA is available in the docket. PHMSA invites comment on the potential environmental impacts of this proposed rule. After reviewing those comments, PHMSA will revise the DEA in response before reaching a final decision on the proposed rule.

I. Executive Order 13132: Federalism

This rulemaking was analyzed in accordance with the principles and criteria contained in E.O. 13132 ("Federalism")[301] and the Presidential Memorandum titled "Preemption."[302] E.O. 13132 requires agencies to assure 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 that this proposed rule will have a substantial direct effect on State and local governments, the relationship between the National Government and the States, or the distribution of power and responsibilities among the various levels of government. This NPRM is not expected to impose substantial direct compliance costs on State and local governments.

While the NPRM could operate to preempt some State requirements if incompatible with the new minimum Federal safety standards, it 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. Section 60104(c) of Federal Pipeline Safety Laws prohibits State safety regulation of interstate

[301] 64 FR 43255 (Aug. 10, 1999).
[302] 74 FR 24693 (May 22, 2009).

pipelines. Under Federal Pipeline Safety Laws, States that have submitted a current certification under section 60105(a) must adopt the minimum Federal pipeline safety requirements for intrastate pipelines and may adopt additional or more stringent requirements so long as they are compatible, including regulating 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. Therefore, the PHMSA expects that the consultation and funding requirements of E.O. 13132 will not apply.

J. Executive Order 13211: Significant Energy Actions

E.O. 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use")[303] requires Federal agencies to prepare a Statement of Energy Effects for any "significant energy action." E.O. 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 a significant action under E.O. 12866; however, it is not anticipated to have a significant adverse effect on supply, distribution, or energy use, as further discussed in

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[303] 66 FR 28355 (May 22, 2001).

the PRIA. Further, 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

E.O. 13609 ("Promoting International Regulatory Cooperation")[304] 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

[304] 77 FR 26413 (May 4, 2012).

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, 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

E.O. 14028 ("Improving the Nation's Cybersecurity")[305] directs the Federal government to improve its efforts to identify, deter, and respond to "persistent and increasingly sophisticated malicious cyber campaigns." 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 pertinent pipeline facilities.

[305] 86 FR 26633 (May 17, 2021).

Operator IM programs, manuals and procedures, and facility design and testing 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[306] could theoretically give rise to more attractive targets for cybersecurity incidents, PHMSA understands the incremental additional risk from those and other of the NPRM's proposed regulatory amendments to be minimal. Carbon dioxide and hazardous liquid pipeline operator compliance strategies for the NPRM's proposed requirements may be subject to current Transportation Security Agency (TSA) pipeline cybersecurity directives[307] and would be subject to ongoing TSA efforts to strengthen cybersecurity and resiliency in the pipeline sector, as discussed within an ANPRM published in November 2022.[308] Further, the 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 hazardous liquid and carbon dioxide pipeline

[306] Pertinent proposals include the following: NPMS data submission requirements pursuant to §195.61; leak detection requirements pursuant to §§195.134 and 195.444; population density survey information collection requirements pursuant to §§ 195.210 and 195.402(c)(17); fixed vapor detection and alarm systems requirements pursuant to §§ 195.263 and 195.452(i)(5); enhanced emergency communications pursuant to § 195.402(e)(9); and vapor dispersion analysis requirements for evaluating whether HVL pipelines could affect an HCA pursuant to § 195.452(f)(1).
[307] _E.g._, TSA, Security Directive Pipeline-2021-01C (May 29, 2023); TSA, Security Directive Pipeline-2021-02D (July 27, 2023).
[308] TSA, "Advance Notice of Proposed Rulemaking: Enhancing Surface Cyber Risk Management," 87 FR 73527 (Nov. 30, 2022).

operators.[309] Lastly, this NPRM's proposed regulatory amendments (including, but not limited to, extension of part 195 requirements to additional carbon dioxide product stream compositions and physical states) would reduce the severity of any pipeline accidents that occur, and therefore this rulemaking could reduce the public safety and the environmental consequences in the event of a cybersecurity incident on pertinent hazard liquid or carbon dioxide pipelines.

PHMSA seeks comment on the above and any other potential cybersecurity impacts of the NPRM's proposed regulatory amendments.

O. Severability

The purpose of this proposed rule is to operate holistically and, in concert with existing part 195 requirements, provide defense-in-depth to address a panoply of issues necessary to ensure safe operation of pipeline facilities, with a focus on carbon dioxide pipelines. 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 operate functionally 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. PHMSA seeks comment on which portions of this rule should or should not be severable.

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

List of Subjects

49 CFR Part 190

Carbon dioxide, Pipeline safety.

49 CFR Part 195

Carbon dioxide, Incorporation by reference, Pipeline safety.

49 CFR Part 196

Carbon dioxide, Pipeline safety.

49 CFR Part 198

Carbon dioxide, Pipeline safety.

In consideration of the foregoing, PHMSA proposes to amend 49 CFR parts 190, 195, 196 and 198 as follows:

PART 190—PIPELINE SAFETY ENFORCEMENT AND REGULATORY PROCEDURES

XX. The authority citation for 49 CFR part 190 is amended to read as follows:

Authority: 33 U.S.C. 1321(b); 49 U.S.C. 60101 *et seq.*; and 49 CFR 1.97.

XX. In § 190.3, revise the definitions of "emergency order" and "imminent hazard" to read as follows:

§ 190.3 Definitions.

* * * * *

Emergency order means a written order issued in response to an imminent hazard imposing restrictions, prohibitions, or safety measures on owners and operators of gas or hazardous liquid (as well as carbon dioxide) pipeline facilities, without prior notice or an opportunity for a hearing.

* * * * *

Imminent hazard means the existence of a condition relating to a gas, hazardous liquid, or carbon dioxide pipeline facility that presents a substantial likelihood that death, serious illness, severe personal injury, or a substantial endangerment to health, property, or the environment may occur before the reasonably foreseeable completion date of a formal proceeding begun to lessen the risk of such death, illness, injury or endangerment.

* * * * *

XX. In § 190.236, revise its title and paragraph (d) to read as follows:

§ 190.236 Emergency orders: Procedures for issuance and rescission.

* * * * *

(d) *Service.* The Administrator will provide service of emergency orders in accordance with § 190.5 to all operators of gas and hazardous liquid (as well as carbon dioxide) pipeline facilities that the Administrator reasonably expects to be affected by the emergency order. In addition, the Administrator will publish emergency orders in the FEDERAL REGISTER and post them on the PHMSA website as soon as practicable upon issuance. Publication in the FEDERAL REGISTER will serve as general notice of an emergency order. Each emergency order must contain information specifying how pipeline operators and owners may respond to the emergency order, filing procedures, and service requirements, including the address of DOT Docket Operations and the names and addresses of all persons to be served if a petition for review is filed.

* * * * *

XX. The title of Part 195 is revised to read as follows:

PART 195 – TRANSPORTATION OF HAZARDOUS LIQUIDS AND CARBON DIOXIDE BY PIPELINE

XX. The authority citation for part 195 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.

XX. In § 195.1, revise paragraphs (b)(8) and (b)(10) and add paragraph (b)(11) to read as follows:

§ 195.1 Which pipelines are covered by this Part?

* * * * *

(b) * * *

(8) Transportation of hazardous liquid through onshore production (including flow lines), refining, or manufacturing facilities or storage or in-plant piping systems associated with such facilities;

* * * * *

(10) Transportation of carbon dioxide downstream from the applicable following point:

(i) The inlet of a compressor used in the injection of carbon dioxide for oil recovery operations, or the point where recycled carbon dioxide enters the injection system, whichever is farther upstream;

(ii) The connection of the first branch pipeline in the production field where the pipeline transports carbon dioxide to an injection well or to a header or manifold from which a pipeline branches to an injection well; or

(iii) The outlet of the pipeline isolation valve located at the wellhead of an injection well used for long-term carbon dioxide storage.

(11) Transportation of carbon dioxide through piping or equipment used in the production (including flow lines), extraction, recovery, lifting, stabilization, separation, or treatment of carbon dioxide or the preparation of carbon dioxide for transportation by pipeline at production (including flow lines), refining, or manufacturing facilities. This exception does not apply to any device and associated piping that are necessary to control pressure in the pipeline under § 195.406(b).

* * * * *

XX. In § 195.2, add the definition of "Close interval survey" in alphabetical order and revise the definitions for "Carbon dioxide", "Entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments", "Highly volatile liquid or HVL", "Line section", "Notification of potential rupture", "Pipeline or pipeline system", and "Rupture-mitigation valve" to read as follows:

§ 195.2 Definitions.

* * * * *

Carbon dioxide means a fluid consisting of more than 50 percent carbon dioxide molecules in any combination of the gas, liquid, or supercritical phases.

* * * * *

Close interval survey means a series of closely and properly spaced pipe-to-electrolyte potential measurements taken over the pipe to assess the adequacy of cathodic protection or to identify locations where a current may be leaving the pipeline that may cause corrosion and for the purpose of quantifying voltage (IR) drops other than those across the structure electrolyte boundary, such as when performed as a current interrupted, depolarized, or native survey.

* * * * *

Entirely replaced onshore hazardous liquid or carbon dioxide pipeline segments, for the purposes of §§ 195.258, 195.260, and 195.418, means where 2 or more miles of pipe, in the aggregate, have been replaced within any 5 contiguous miles within any 24-month period.

*   *   *   *   *

Highly volatile liquid or *HVL* means:

(1) a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa (40 psia) at 37.8 °C (100 °F); or

(2) carbon dioxide.

*   *   *   *   *

Line section means a continuous run of pipe between adjacent pressure pump stations or compressor stations, between a pressure pump station and terminal or breakout tanks, between a pressure pump station or compressor station and a block valve, or between adjacent block valves.

*   *   *   *   *

Notification of potential rupture means the notification to, or observation by, an operator of indicia identified in § 195.417 of a potential unintentional or uncontrolled release of a large volume of commodity from a pipeline.

*   *   *   *   *

Pipeline or *pipeline system* means all parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation, including, but not limited to, line pipe, valves, and other appurtenances connected to line pipe, pumping units or compressing units, fabricated assemblies associated with pumping units or compressing units, metering and delivery stations and fabricated assemblies therein, and breakout tanks.

*   *   *   *   *

Rupture-mitigation valve (RMV) means an automatic shut-off valve (ASV) or a remote-control valve (RCV) that a pipeline operator uses to minimize the volume of hazardous liquid or carbon dioxide released from the pipeline and to mitigate the consequences of a rupture.

* * * * *

XX. In § 195.3, revise paragraph (b)(13) to read as follows:

§ 195.3 What documents are incorporated by reference partly or wholly in this part?

(b) *American Petroleum Institute (API), 1220 L Street NW., Washington, DC 20005, and phone: 202-682-8000, Web site: http://api.org/.*

* * * * *

(13) API Specification 5L, "Specification for Line Pipe," 45th edition, effective July 1, 2013, (ANSI/API Spec 5L), IBR approved for §§ 195.106(b) and (e) and 195.111.

* * * * *

XX. Revise § 195.5 to read as follows:

§ 195.5 Conversion to service subject to this part.

(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to accomplish, prior to placing the converted pipeline into service subject to this part unless otherwise specified, the following:

(1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in satisfactory condition for safe operation. If one or more of the variables necessary to verify the design pressure under § 195.106 or to perform the

testing under paragraph (a)(5) of this section is unknown, the design pressure may be verified and the maximum operating pressure determined by:

(i) Testing the pipeline in accordance with ASME/ANSI B31.8 (incorporated by reference, *see* § 195.3), Appendix N, to produce a stress equal to the yield strength; and (ii) Applying, to not more than 80 percent of the first pressure that produces a yielding, the design factor F in § 195.106(a) and the appropriate factors in § 195.106(e).

(2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or integrity of the pipeline.

(3) Notwithstanding the requirements in paragraph (a)(1) of this section, each operator of an onshore or offshore pipeline segment being converted to service under this part beginning on [INSERT THE EFFECTIVE DATE OF THE FINAL RULE] to transport hazardous liquid or carbon dioxide must comply with the design and construction requirements of subparts C and D of this part for a segment of pipeline that is new, replaced, relocated, or otherwise changed, prior to placing the converted pipeline into service.

(4) All known unsafe defects and conditions must be corrected in accordance with this part.

(5) The pipeline must be tested in accordance with subpart E of this part to substantiate the maximum operating pressure permitted by § 195.406. Each pipeline converted to service under this part beginning on [INSERT THE EFFECTIVE DATE OF THE FINAL RULE] to transport carbon dioxide must also be spike tested in accordance with § 195.309 of this part.

(b) A pipeline that qualifies for use under this section is not required to comply with the corrosion control requirements of subpart H of this part until 12 months after it is placed into service, notwithstanding any previous deadlines for compliance.

(c) Each operator of a pipeline being converted to service under this part beginning on [INSERT THE EFFECTIVE DATE OF THE FINAL RULE] to transport carbon dioxide must perform a close interval survey of the pipeline within 15 months of placing the converted pipeline into service. Close interval survey is not required where the operator determines and documents that close interval survey is not possible for geographical, technical, or safety reasons.

(1) Each operator must complete close interval surveys required by paragraph (c) of this section with the protective current interrupted unless the operator determines and documents that interrupting protective current is not possible for technical or safety reasons. If a pipeline being converted to service does not have the capability to interrupt necessary sources of cathodic protection current, the operator must upgrade the cathodic protection system to be capable of current interruption prior to performing the close interval survey.

(2) Each operator must promptly correct any deficiencies indicated by the inspection and testing required by paragraph (c) of this section. The operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. The operator must complete the remedial action promptly, but no later than the earliest of the following: within 12 months of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

(d) Each operator of a pipeline being converted to service under this part beginning on [INSERT THE EFFECTIVE DATE OF THE FINAL RULE] to transport carbon dioxide must perform pipeline coating surveys to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating. Coating surveys of the pipeline must be performed within 15 months of placing the converted pipeline into service. Coating surveys are not required where the operator determines and documents that effective coating surveys are not possible for geographical, technical, or safety reasons.

(1) An operator must notify PHMSA in accordance with § 195.18 at least 90 days in advance of using other technology to perform the pipeline coating surveys required under paragraph (d) of this section.

(2) An operator must repair any coating damage classified as severe (indicated by a voltage drop greater than 60 percent for DCVG or 70 dBµV for ACVG) in accordance with the requirements of paragraph (c)(2) of this section.

(e) Each operator of a pipeline being converted to service under this part beginning on [INSERT THE EFFECTIVE DATE OF THE FINAL RULE] to transport carbon dioxide must assess the integrity of the line pipe by in-line inspection as described in paragraphs (c) through (h) of § 195.416 and § 195.452 of this part, as applicable, for the range of relevant threats to the pipeline segment, within 12 months after placing the converted pipeline into service. Each operator must follow the requirements of § 195.401 if a condition that could adversely affect the safe operation of a pipeline is discovered during the assessment performed under this paragraph.

(f) Each operator must keep for the life of the pipeline a record of the investigations, tests, repairs, replacements, and alterations made under the requirements of this section.

(g) An operator converting a pipeline previously used in service not subject to this part must notify PHMSA 60 days before the conversion occurs as required by § 195.64.

XX. Revise 195.8 to read as follows:

§ 195.8 Transportation of hazardous liquid or carbon dioxide in pipelines constructed with other than steel pipe.

No person may transport any hazardous liquid or carbon dioxide through a pipe that is constructed after October 1, 1970, for hazardous liquids; constructed after July 12, 1991, for carbon dioxide consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state; or constructed after [INSERT EFFECTIVE DATE OF THIS FINAL RULE], for all other carbon dioxide, (*see* § 195.2), of material other than steel, unless the person has notified PHMSA in writing at least 90 days before the transportation is to begin. The notice must state whether carbon dioxide (and the phase thereof) or a hazardous liquid is to be transported and the chemical name, common name, properties and characteristics of the hazardous liquid to be transported and the material used in construction of the pipeline. If PHMSA determines that the transportation of the hazardous liquid or carbon dioxide in the manner proposed would be unduly hazardous, PHMSA will, within 90 days after receipt of the notice, order the person that gave the notice, in writing, not to transport the hazardous liquid or carbon dioxide in the proposed manner until further notice.

XX. In § 195.18, revise paragraph (c) to read as follows:

§ 195.18 How to notify PHMSA.

*   *   *   *   *

(c) Unless otherwise specified, if an operator submits, pursuant to § 195.5, § 195.258, § 195.260, § 195.418, § 195.419, § 195.420 or § 195.452 a notification requesting use of a different integrity assessment method, analytical method, sampling approach, compliance timeline, 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 that other method, approach, compliance timeline, or technique. An operator may proceed to use the other method, approach, compliance timeline, or technique 91 days after submittal of the notification unless or until the operator receives a written response from PHMSA informing the operator that PHMSA objects to the proposal, or that PHMSA requires additional time or additional information to conduct its review.

XX. Revise § 195.48 to read as follows:

§ 195.48 Scope.

This Subpart prescribes requirements for periodic reporting and for reporting of accidents and safety-related conditions. This Subpart applies to all pipelines subject to this Part. An operator of a Category 3 rural low-stress pipeline meeting the criteria in § 195.12 is not required to complete those parts of DOT Form PHMSA F 7000-1.1 associated with IM or high consequence areas.

XX. Revise § 195.49 to read as follows:

§ 195.49 Annual report.

Each operator must annually complete and submit DOT Form PHMSA F 7000-1.1 for each type of pipeline facility operated at the end of the previous year. An operator must submit the annual report by June 15 each year. A separate report is required for pipelines transporting crude oil, non-carbon dioxide HVLs (including anhydrous ammonia), petroleum products, carbon dioxide, and fuel grade ethanol. For each State a pipeline traverses, an operator must separately complete those sections on the form requiring information to be reported for each State.

XX. Revise § 195.54 to read as follows:

§ 195.54 Accident reports.

(a) Each operator that experiences an accident that is required to be reported under § 195.50 must, as soon as practicable, but not later than 30 days after discovery of the accident, file an accident report on DOT Form PHMSA F 7000-1 for hazardous liquid and carbon dioxide pipeline systems, or on DOT Form PHMSA F 7000-2 for gravity and reporting-regulated-only gathering hazardous liquid pipelines.

(b) Whenever an operator receives any changes in the information reported or additions to the original report on DOT Form PHMSA F 7000-1 or PHMSA F 7000-2, it must file a supplemental report within 30 days.

XX. In § 195.55, revise the introductory text of paragraph (b) and paragraph (b)(1) to read as follows:

§ 195.55 Reporting safety-related conditions.

* * * * *

(b) A report is not required for any safety-related condition that:

(1) Exists on a pipeline not transporting an HVL that is more than 220 yards (200 meters) from any building intended for human occupancy or outdoor place of assembly, except that reports are required for conditions within the right-of-way of an active railroad, paved road, street, or highway, or that occur offshore or at onshore locations where a loss of hazardous liquid could reasonably be expected to pollute any stream, river, lake, reservoir, or other body of water;

* * * * *

XX. In § 195.61, revise the introductory text of paragraph (a) to read as follows:

§ 195.61 National Pipeline Mapping System.

(a) Each operator of a pipeline facility must provide the following geospatial data to PHMSA for that facility:

* * * * *

XX. Revise § 195.111 to read as follows:

§ 195.111 Fracture propagation.

(a) *General.* Except as provided in paragraph (d) of this section, a carbon dioxide pipeline constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5 on or after [INSERT EFFECTIVE DATE OF THIS FINAL RULE] must be designed to mitigate the effects of fracture propagation, including the following:

(1) Ensure resistance to fracture initiation while addressing the full range of operating temperatures, pressures, product compositions, pipe grade, and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions, that the pipeline is expected to experience. If these parameters change during operation of the pipeline such that they are outside the bounds of what was considered in the design evaluation, the evaluation and operating procedures must be reviewed and updated to assure continued resistance to fracture initiation over the operating life of the pipeline;

(2) Address adjustments to toughness of pipe for each grade used and the decompression behavior of the carbon dioxide at operating parameters;

(3) Ensure at least 99-percent probability of fracture arrest within eight pipe lengths with a probability of not less than 90-percent within five pipe lengths; and

(4) Include fracture toughness testing that is equivalent to that described in the supplementary requirements of Annex G of API Specification 5L (incorporated by reference, *see* § 195.3) for shear fracture area, Charpy v-notch impact test, and drop weight tear test and ensure ductile fracture and arrest as follows:

(i) The results of the Charpy v-notch impact test prescribed in Annex G must indicate at least 85-percent average shear fracture area; and

(ii) The results of the drop weight tear test prescribed in Annex G must indicate 85-percent average shear fracture area with a minimum single test result of 80-percent shear fracture area for any steel test samples. The test results must ensure a ductile fracture and arrest.

(b) *Toughness.* The toughness properties for pipe must address the potential for initiation, propagation and arrest of fractures in accordance with:

(1) Annex G of API Specification 5L (incorporated by reference, *see* § 195.3); and

(2) Any correction factors needed to address pipe grades, pressures, temperatures, or product compositions not expressly addressed in Annex G of API Specification 5L (incorporated by reference, *see* § 195.3).

(c) *Alternative measures.* If it is not physically possible to achieve the pipeline toughness properties of paragraphs (a) and (b) of this section, additional design features, such as mechanical or composite crack arrestors, heavier walled pipe of proper design and spacing, must be used to ensure fracture arrest as described in paragraph (a)(3) of this section.

(d) *Legacy pipelines.* A carbon dioxide pipeline system transporting a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state and constructed prior to [INSERT EFFECTIVE DATE OF THIS FINAL RULE] must be designed to mitigate the effects of fracture propagation.

XX. In § 195.116, revise paragraph (c) to read as follows:

§ 195.116 Valves.

* * * * *

(c) Each part of the valve that will be in contact with the carbon dioxide or hazardous liquid stream must be made of materials that are compatible with each product stream, carbon dioxide, and each hazardous liquid that is anticipated to flow through the pipeline system.

* * * * *

XX. In § 195.120, revise paragraph (b) to read as follows:

§ 195.120 Passage of internal inspection devices.

* * * * *

(b) *Exceptions.* This section does not apply to:

(1) Manifolds;

(2) Station piping such as at pump stations, compressor stations, meter stations, or pressure reducing stations;

(3) Piping associated with tank farms and other storage facilities;

(4) Cross-overs, such as at mainline valves and between parallel pipelines;

(5) Pipe for which an instrumented internal inspection device is not commercially available; and

(6) Offshore pipelines, other than lines 10 inches (254 millimeters) or greater in nominal diameter, that transport liquids to onshore facilities.

* * * * *

XX. Revise § 195.134 to read as follows:

§ 195.134 Leak detection.

(a) *Scope.* This section applies to each pipeline transporting hazardous liquid in single phase (without gas in the liquid) or carbon dioxide.

(b) *General.*

(1) Each pipeline transporting hazardous liquids constructed prior to October 1, 2019, must have a system for detecting leaks that complies with the requirements in § 195.444 by October 1, 2024.

(2) Each pipeline transporting hazardous liquids constructed on or after October 1, 2019, must have a system for detecting leaks that complies with the requirements in § 195.444 by October 1, 2020.

(3) Each pipeline transporting carbon dioxide constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5 prior to [INSERT EFFECTIVE DATE OF THIS FINAL RULE], must have a system for detecting leaks that complies with the requirements in § 195.444 by [INSERT DATE 48 MONTHS AFTER THE EFFECTIVE DATE OF THIS FINAL RULE]. If the pipeline transports supercritical- or liquid-phase carbon dioxide, this leak detection system must be a computational pipeline modeling (CPM) leak detection system and comply with the requirements in §§ 195.134(c) and 195.444(c).

(4) Each pipeline transporting carbon dioxide constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5 on or after [INSERT EFFECTIVE DATE OF THIS FINAL RULE], must have a system for detecting leaks that complies with the requirements in § 195.444 by INSERT EFFECTIVE DATE OF THIS FINAL RULE]. If the pipeline transports supercritical- or liquid-phase carbon dioxide, this leak detection system must be a computational pipeline modeling (CPM) leak detection system and comply with the requirements in §§ 195.134(c) and 195.444(c).

* * * * *

XX. Revise § 195.210 and its title to read as follows:

§ 195.210 Proximity to residences and other places.

(a) Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing residences, businesses, and places of public assembly.

(b) For any pipeline located within 50 feet (15 meters) of any residence, business, or place of public assembly in which persons work, congregate, or assemble, the operator must provide the pipeline with at least 12 inches (305 millimeters) of cover in addition to that prescribed in § 195.248.

(c) For any onshore pipeline transporting carbon dioxide located within 2 miles (3.22 kilometers) of any residence, business, or place of public assembly in which persons work, congregate, or assemble, the operator must:

(i) Maintain records for the life of the pipeline facility that demonstrate the reasons the location was impracticable to avoid.

(ii) Perform a population density survey along the pipeline route to establish an emergency planning zone. All buildings intended for human occupancy (including residences and businesses) and places of public assembly within two miles on either side of the pipeline centerline must be included. The survey must collect data including the number of affected entities (including any residents or occupants), their ages, preferred language, primary and secondary phone numbers, and any specific evacuation information, such as special access routes into buildings, and if additional help in evacuation is required.

(iii) Distribute emergency response information to each building intended for human occupancy (including residences and businesses) and places of public assembly identified in paragraph (c)(ii) before initial operations of the carbon dioxide pipeline commence. The emergency response information must meet the requirements at § 195.440(d), (f), and (g). If the building intended for human occupancy (including residences and businesses) or place of public assembly is determined to be within a location that could be affected by the release of carbon dioxide pursuant to the vapor dispersion analysis required under § 195.452(f)(1) or the default 2-mile distance noted at § 195.456(a), such information should include an explicit statement of that determination and identify any precautions the public in those locations should take in the event of an emergency.

XX. Revise § 195.248 to read as follows:

§ 195.248 Cover over buried pipeline.

(a) Unless specifically exempted in this subpart, all pipe must be buried so that it is below the level of cultivation. Except as provided in paragraph (b) of this section, the pipe must be installed so that the cover between the top of the pipe and the ground level, road bed, river bottom, or underwater natural bottom (as determined by recognized and generally accepted practices), as applicable, complies with the following table:

Location	Cover inches (millimeters)	
	For normal excavation	For rock excavation[1]
Industrial, commercial, and residential areas	36 (914)	30 (762)
Agricultural areas	48 (1219)[2]	N/A
Crossing of inland bodies of water with a width of at least 100 feet (30.5 meters) from high water mark to high water mark	48 (1219)	18 (457)
Drainage ditches at public roads and railroads	36 (914)	36 (914)
Deepwater port safety zones	48 (1219)	24 (610)
Gulf of Mexico and its inlets in waters less than 15 feet (4.6 meters) deep as measured from mean low water	36 (914)	18 (457)
Other offshore areas under water less than 12 ft (3.7 meters) deep as measured from mean low water	36 (914)	18 (457)
Any other area	30 (762)	18 (457)

[1] Rock excavation is any excavation that required blasting or removal by equivalent means.
[2] Pipelines may require deeper burial to avoid damage from deep plowing; the designer is cautioned to account for this possibility.

* * * * *

XX. In § 195.260, revise paragraph (a) and the introductory text of paragraph (g) to read as follows:

§ 195.260 Valves: Location.

* * * * *

(a) On the suction end and the discharge end of a pump station or compressor station in a manner that permits isolation of the pump station or compressor station equipment in the event of an emergency.

* * * * *

(g) On each highly volatile liquid (HVL) pipeline (including each pipeline that transports carbon dioxide) that is located in a high-population area or other populated area, as defined in § 195.450, and that is constructed, or where 2 or more miles of pipe have been replaced within any 5 contiguous miles within any 24-month period, after April 10, 2023, with a maximum valve spacing of 7½ miles. The maximum valve spacing intervals may be increased by 1.25 times the distance up to a 9 3/8-mile spacing, provided the operator:

* * * * *

XX. Revise § 195.262 and its title to read as follows:

§ 195.262 Pumping and compressing equipment.

(a) Adequate ventilation must be provided in pump station and compressor station buildings to prevent the accumulation of hazardous vapors. Warning devices must be installed to warn of the presence of hazardous vapors in any pump station or compressor station building.

(b) The following must be provided in each pump station and compressor station:

(1) Safety devices that prevent overpressuring of pumping equipment and compressing equipment, including the auxiliary pumping equipment within the pump station and auxiliary compressing equipment within the compressor station.

(2) A device for the emergency shutdown of each pump station and compressor station.

(3) If power is necessary to actuate the safety devices, an auxiliary power supply.

(c) Each safety device must be tested under conditions approximating actual operations and found to function properly before the pump station or compressor station may be used.

(d) Except for offshore pipelines, pumping equipment and compressing equipment must be installed on property that is under the control of the operator and at least 15.2 m (50 ft) from the boundary of the pump station or compressor station.

(e) Adequate fire protection must be installed at each pump station and compressor station. If the fire protection system installed requires the use of pumps, motive power must be provided for those pumps that is separate from the power that operates the station.

XX. Add § 195.263 to read as follows:

§ 195.263 Fixed vapor detection and alarm systems.

(a) *General.* Each pump station, compressor station, meter station, and valve station (including facilities for launching and receiving in-line inspection tools or instrumented internal inspection devices) on a pipeline transporting an HVL that is constructed, replaced, relocated, otherwise changed, or converted to service under § 195.5 on or after [INSERT EFFECTIVE DATE OF THIS FINAL RULE] must have a fixed vapor detection and alarm system.

(b) *Capabilities.* Except when shutdown of the system is necessary for maintenance, each fixed vapor detection and alarm system required by this section must:

(1) Be capable of detecting any product or deleterious constituent that might be transported in concentrations above those described in paragraph (b)(2) of this section;

(2) Continuously monitor for concentrations of not more than 25 percent of the lower explosive limit for flammability, and 25 percent of the of NIOSH IDLH for asphyxiation and toxicity hazards, whichever is lower;

(3) If a concentration of vapor from paragraph (b)(2) of this section is detected, warn persons about to enter or inside the area of the danger with audible and visual alarms and provide a notification to personnel in an operational control center.

XX. In § 195.302, revise paragraph (b)(2) and add paragraph (b)(5) to read as follows:

§ 195.302 General requirements.

* * * * *

(b) * * *

(2) Any carbon dioxide pipeline whose maximum operating pressure is established under § 195.406(a)(5) that:

(i) Transports a fluid consisting of greater than 90 percent carbon dioxide molecules compressed to a supercritical state and was constructed before July 12, 1991;

(ii) Transports a fluid consisting of more than 50 percent but less than or equal to 90 percent carbon dioxide molecules compressed to a supercritical state and was constructed before [INSERT THE EFFECTIVE DATE OF THIS FINAL RULE]; or

(iii) Transports a fluid consisting of more than 50 percent carbon dioxide molecules in any combination of gas and liquid phases and was constructed before [INSERT THE EFFECTIVE DATE OF THIS FINAL RULE].

* * * * *

(5) Any carbon dioxide pipeline that is located in a rural area as part of a production field distribution system and was constructed before July 12, 1991.

* * * * *

XX. Revise paragraph (c) of § 195.306 to read as follows:

§ 195.306 Test medium.

* * * * *

(c) Carbon dioxide pipelines may use inert gas (excluding carbon dioxide) as the test medium if—

* * * * *

XX. Add § 195.309 to read as follows:

§ 195.309 Spike hydrostatic pressure test.

(a) *Spike test requirements.* Whenever a segment of hazardous liquid or carbon dioxide pipeline is required to be spike tested under this part, the spike hydrostatic pressure test must be conducted in accordance with the requirements of this section and the remaining, applicable portions of subpart E.

(1) The test must use water as the test medium.

(2) The baseline test pressure must be maintained throughout the part of the system being tested at a pressure equal to 125 percent, or more, of the MOP.

(3) The test must be conducted by maintaining a pressure at or above the baseline test pressure for at least 8 hours.

(4) After the test pressure stabilizes at the baseline pressure and within the first 2 hours of the 8-hour test interval, the hydrostatic pressure must be raised (spiked) to a minimum of the

lesser of 1.5 times MOP or 100% SMYS. This spike hydrostatic test pressure must be held for at least 30 minutes after the spike hydrostatic test pressure stabilizes.

XX. In § 195.401, revise paragraph (c)(4) and add paragraphs (c)(6) and (c)(7) to read as follows:

§ 195.401 General requirements.

*   *   *   *   *

(c) *   *   *

(4) A pipeline on which construction was begun after July 11, 1991, that transports a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.

*   *   *   *   *

(6) A pipeline on which construction was begun on or after [INSERT EFFECTIVE DATE OF THIS FINAL RULE], that transports a fluid consisting of more than 50 percent but less than or equal to 90 percent carbon dioxide molecules compressed to a supercritical state.

(7) A pipeline on which construction was begun on or after [INSERT EFFECTIVE DATE OF THIS FINAL RULE], that transports a fluid consisting of more than 50 percent carbon dioxide molecules in any combination of gas and liquid phases.

XX. In § 195.402, add paragraph (c)(16) and subparagraph (c)(5)(iv), revise paragraphs (c)(14), (e)(3), and (e)(8), renumber paragraphs (e)(9) and (e)(10) to (e)(10) and (e)(11), respectively, add paragraph (e)(9), and delete paragraph (g) to read as follows:

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

*   *   *   *   *

(c) *   *   *

(5) * * *

(iv) The requirements of paragraph (c)(5) do not apply to gathering lines, except that each operator of such lines must in the manual required by paragraph (a) of this section include procedures for analyzing pipeline accidents to determine their causes.

* * * * *

(14) Taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, on-site fire control equipment, devices capable of detecting hazardous concentrations of vapor or gas, emergency rescue equipment, including a breathing apparatus, and a rescue harness and line.

* * * * *

(16) Operators of carbon dioxide pipelines must provide local emergency response organizations with, and train them on the proper use of, any equipment, instruments, tools, and materials necessary for use in the event of an emergency on a carbon dioxide pipeline.

(17) Once per calendar year, but not to exceed 15 months, operators of onshore carbon dioxide pipelines must perform a population density survey along the pipeline route to establish (if not previously established at § 195.210), and subsequently update each calendar year thereafter, an emergency planning zone. All buildings intended for human occupancy (including residences and businesses) and places of public assembly within two miles on either side of the pipeline centerline must be identified. The survey must collect data including the number of affected entities (including residents and occupants), their ages, preferred language, primary and secondary phone numbers, and any specific evacuation information such as special access routes into buildings, and if additional help in evacuation is required.

* * * * *

(e) * * *

(3) Having personnel, equipment, instruments, tools, and materials available as needed at the scene of an emergency, including equipment, instruments, and tools capable of detecting hazardous concentrations of hazardous liquid, carbon dioxide, and known deleterious product stream constituents.

* * * * *

(8) In the case of failure of a pipeline system transporting a highly volatile liquid (including carbon dioxide), use of appropriate instruments to assess the extent and coverage of the vapor cloud and determine the hazardous areas.

(9) In the case of an emergency on an onshore pipeline system transporting carbon dioxide and as soon as practicable after identifying an emergency on the pipeline, initiate an automatic notification system that will contact the affected entities (including residents and occupants) within the emergency planning zone of the pipeline with a message indicating that an emergency exists and what safety precautions members of the public should take. Operators must transmit additional messages to affected entities throughout the emergency as critical safety information is updated or the emergency is resolved. All communications required by this paragraph must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area. Operators must use the contact information obtained at paragraph (c)(17) of this section or at § 195.210 to meet the requirements of this section, to determine if additional assistance is required to aid in the evacuation process, and to inform appropriate Federal, State, regional,

county, local, and tribal emergency response officials.

*　　*　　*　　*　　*

(g) [Reserved].

XX. In § 195.403, revise paragraph (a)(4) to read as follows:

§ 195.403 Emergency response training.

(a)　　*　　*　　*

(4) Take steps necessary to control any accidental release of hazardous liquid or carbon dioxide and to minimize the potential for fire, explosion, toxicity, asphyxiation, or environmental damage; and

*　　*　　*　　*　　*

XX. In § 195.404, revise paragraph (a)(1)(ii) to read as follows:

§ 195.404 Maps and records.

(a)　　*　　*　　*

(1)　　*　　*　　*

(ii) Pump stations and compressor stations;

*　　*　　*　　*　　*

XX. In § 195.406, revise paragraph (a)(5) to read as follows:

§ 195.406 Maximum operating pressure.

(a)　　*　　*　　*

(5) For pipelines under § 195.302(b)(1) and (b)(2) that have not been pressure tested under subpart E of this part, 80 percent of the test pressure or highest operating pressure to which the pipeline was subjected for 4 or more continuous hours that can be demonstrated by recording charts or logs made at the time the test or operations were conducted.

* * * * *

XX. In § 195.412, revise paragraph (a) and add paragraphs (c), (d), and (e) to read as follows:

§ 195.412 Inspection of rights-of-way and crossings under navigable waters.

(a) Each operator must, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on and adjacent to each pipeline right-of-way for indications of leakage, construction activity, geologic hazards, reduced depth of cover, and other factors that may affect pipeline integrity, safety, and operation. Methods of inspection include walking, driving, flying or other appropriate means of traversing and inspecting the right-of-way.

* * * * *

(c) Whenever an operator observes an indication of geologic hazards on or adjacent to a pipeline right-of-way, the operator must perform additional inspections and evaluations, determine the extent of the geologic hazards and the impact of those hazards on the pipeline, and take remedial action, according to the requirements of § 195.401(b), if necessary.

(d) Whenever an operator observes an indication that the depth of cover over a buried pipeline is less than that required by § 195.248, the operator must perform additional inspections and evaluations, determine the extent of the reduced depth of cover and the impact of the reduced depth of cover over the buried pipeline, and take remedial action, according to the requirements of § 195.401(b), if necessary.

(e) Records of additional inspections, evaluations, determinations of need for remedial action, and remedial actions performed under paragraphs (c) and (d) of this section must be maintained for the life of the pipeline.

XX. In § 195.417, delete paragraph (c) to read as follows:

§ 195.417 Notification of potential rupture.

* * * * *

(c) [Reserved].

XX. Add § 195.429 to read as follows:

§ 195.429 Maintenance and testing of fixed vapor detection and alarm systems.

(a) Each operator shall maintain each fixed vapor detection and alarm system to function properly.

(b) Each operator must, at least once per calendar year, but at intervals not exceeding 15 months, test each fixed vapor detection and alarm system under conditions approximating actual operations. Testing must include tests of the individual components of the system and the entire system.

XX. Revise § 195.434 to read as follows:

§ 195.434 Signs.

Each operator must maintain signs visible to the public around each pump station, compressor station, and breakout tank area. Each sign must contain the name of the operator and a telephone number (including area code) where the operator can be reached at all times.

XX. Revise § 195.436 to read as follows:

§ 195.436 Security of facilities.

Each operator must provide protection for each pump station, compressor station, and breakout tank area, and other exposed facility (such as scraper traps) from vandalism and unauthorized entry.

XX. Revise § 195.438 to read as follows:

§ 195.438 Smoking or open flames.

Each operator must prohibit smoking and open flames in each pump station area, compressor station area, and each breakout tank area where there is a possibility of the leakage of a flammable hazardous liquid or of the presence of flammable vapors.

XX. In §195.444, revise paragraphs (a) and (c) to read as follows:

§ 195.444 Leak detection.

(a) *Scope.* Except for offshore gathering and regulated rural gathering pipelines, this section applies to all pipelines transporting hazardous liquid in single phase (without gas in the liquid) or carbon dioxide.

* * * * *

(c) *CPM leak detection systems.* Each computational pipeline monitoring (CPM) leak detection system installed on a pipeline transporting hazardous liquid or carbon dioxide must comply with API RP 1130 (incorporated by reference, *see* § 195.3) in operating, maintaining, testing, record keeping, and dispatcher training of the system.

XX. In § 195.450, revise the introductory text to read as follows:

§ 195.450 Definitions.

The following definitions apply to this section and §§ 195.452, 195.454, and 195.456 and wherever used in this part:

* * * * *

XX. In § 195.452, add new paragraph (i)(5) and revise paragraphs (e)(1)(iv), (f)(1), (i)(1), (i)(2)(iii), and (i)(4) to read as follows:

§ 195.452 Pipeline integrity management in high consequence areas.

* * * * *

(e) * * *

(1) * * *

(iv) Product transported, including deleterious constituents such as hydrogen sulfide and water;

(f) * * *

(1) A process for identifying which pipeline segments could affect a high consequence area, including a vapor dispersion analysis performed according to § 195.456 if the pipeline segment transports an HVL;

* * * * *

(i) * * *

(1) *General requirements.* An operator must take measures to prevent and mitigate the consequences of a pipeline failure that could affect a high consequence area. These measures include conducting a risk analysis of the pipeline segment to identify additional actions to enhance public safety or environmental protection. Such actions may include, but are not limited to, implementing damage prevention best practices, better monitoring of cathodic protection where corrosion is a concern, establishing shorter inspection intervals, installing EFRDs on the pipeline segment, installing fixed vapor detection and alarm systems on pipeline facilities transporting HVLs, modifying the systems that monitor pressure and detect leaks, providing additional training to personnel on response procedures, conducting drills with local emergency responders and adopting other management controls.

(2) * * *

(iii) Characteristics of the product transported, including deleterious constituents such as hydrogen sulfide and water;

* * * * *

(4) *Emergency Flow Restricting Devices (EFRD).* If an operator determines that an EFRD is needed on a pipeline segment to protect a high consequence area in the event of a hazardous liquid or carbon dioxide pipeline release, an operator must install the EFRD. In making this determination, an operator must, at least, evaluate the following factors: the swiftness of leak detection and pipeline shutdown capabilities, the type of commodity carried, the rate of potential leakage, the volume that can be released, topography or pipeline profile, the potential for ignition, proximity to power sources, location of nearest response personnel, specific terrain within the HCA and between the pipeline segment and the HCA it could affect, and benefits expected by reducing the spill or release size. An RMV installed under this paragraph must meet all of the other applicable requirements in this part.

* * * * *

(5) *Fixed Vapor Detection and Alarm Systems.* No later than [INSERT DATE 24 MONTHS AFTER THE EFFECTIVE DATE OF THE FINAL RULE], an operator of a pipeline transporting an HVL must have a fixed vapor detection and alarm system meeting the requirements of § 195.263 at each pump station, compressor station, meter station, and valve station (including facilities for launching and receiving in-line inspection tools or instrumented internal inspection devices) that is located in or could affect an HCA.

* * * * *

XX. Add § 195.456 to subpart F, sequentially under the existing undesignated center heading of "Pipeline Integrity Management", to read as follows:

§ 195.456 Vapor dispersion analysis.

(a) *Applicability.* Whenever an operator of a pipeline is required by this part to perform a vapor dispersion analysis, the operator must meet the requirements of this section. As an alternative to using a validated, engineering-based model in accordance with paragraph (b) of this section, an operator may conclude without performing such an analysis that a high consequence area (HCA) within 2 miles on either side of the pipeline could be affected by a release.

(b) *Analysis.* An operator must use a validated, engineering-based model and must include in its analysis, each of the following elements to determine the distance a release could affect an HCA for each pipeline segment:

(1) The physical and thermodynamic properties and characteristics of the product the pipeline is transporting and operating conditions of the pipeline, including but not limited to maximum operating pressure, temperature, maximum flow rate, hydraulic gradient of the pipeline, density, and vapor pressure;

(2) The diameter of the pipeline, the potential release volume, and the distance between the isolation points;

(3) Release characteristics, including release rates (instantaneous or continuous), orientation of the release, and phase composition of the release;

(4) Concentrations of released product, in terms of flammability, asphyxiation, and toxicity, at which the operator determines the pipeline segment could affect an HCA.

(5) Terrain surrounding the pipeline, including natural topography (e.g., valleys, ravines, hills, and low-lying areas) and manmade structures (e.g., buildings, roadways, ditches, and canals);

(6) Vegetation in any area that could interact with released vapor; and

(7) Typical weather conditions that could affect released vapor, including but not limited to humidity, prevailing winds, and temperature.

(c) *Analysis updates.* Each operator using a validated, engineering-based model must review and update the analysis performed under paragraph (b) of this section at intervals not exceeding 15 months, but at least once each calendar year. In performing this review, operators must evaluate and document any material changes made to the model itself or elements used in the analysis described in paragraph (b)(1) of this section.

(d) *Documentation.* Each operator must make and maintain records of the analysis, review, and any update performed pursuant to this section in accordance with § 195.452(l).

XX. Revise § 195.579 and its title to read as follows:

§ 195.579 Internal corrosion control: Monitoring and mitigation.

(a) *General.* Each operator of a pipeline facility that transports any hazardous liquid or carbon dioxide that would corrode the pipeline, must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion.

(b) *Inhibitors.* Each operator using corrosion inhibitors to mitigate internal corrosion must -

(1) Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect;

(2) Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and

(3) Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7½ months.

(c) Removing pipe. Whenever an operator removes pipe from a pipeline, each operator must inspect the internal surface of the pipe for evidence of corrosion. Each operator that finds

internal corrosion requiring corrective action under § 195.585, must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe.

(d) *Breakout tanks.* After October 2, 2000, each operator that installs a tank bottom lining in an aboveground breakout tank built to API Spec 12F (incorporated by reference, *see* § 195.3), API Std 620 (incorporated by reference, *see* § 195.3), API Std 650 (incorporated by reference, *see* § 195.3), or API Std 650's predecessor, Standard 12C, must install the lining in accordance with API RP 652 (incorporated by reference, *see* § 195.3). However, the operator does not need to comply with API RP 652 when installing any tank for which the operator notes in the corrosion control procedures established under § 195.402(c)(3) why compliance with all or certain provisions of API RP 652 is not necessary for the safety of the tank.

(e) *Internal corrosion control: Carbon dioxide pipeline monitoring and mitigation.* Each operator of a pipeline transporting carbon dioxide must develop and implement a monitoring and mitigation program to mitigate the corrosive effects of the combined constituents in the product stream, as necessary. Pipelines transporting a fluid consisting of greater than 90 percent carbon dioxide molecules compressed to a supercritical state that were constructed or converted to part 195 service before [INSERT THE EFFECTIVE DATE OF THE FINAL RULE] must comply with the requirements of this paragraph no later than [INSERT THE DATE 12 MONTHS AFTER THE EFFECTIVE DATE OF THE FINAL RULE]. Potential corrosion-affecting constituents include, but are not limited to, microbes, H_2O (water), O_2 (oxygen), CH_4 (methane), H_2S (hydrogen sulfide), CO (carbon monoxide), SO_x (sulfur oxides), and NO_x (nitrogen oxides). An operator must evaluate the individual and combined effects of the applicable corrosion-affecting constituents in the product stream, at the operating temperatures and pressures of the pipeline, on the internal corrosion of the pipe and implement mitigation measures, as necessary. The monitoring and mitigation program must include:

(1) The use of quality monitoring methods at points where carbon dioxide containing corrosion-affecting constituents enters the pipeline to determine the presence and quantity of corrosion-affecting constituents.

(2) Technology to mitigate the corrosion-affecting constituents, which may include product sampling, inhibitor injections, in-line cleaning pigging, separators, or other technology that mitigates potentially corrosive effects. The operator must use technology to:

(i) Allow no free water and otherwise limit water to 50 ppm by volume of total product in any phase.

(ii) Limit hydrogen sulfide (H_2S) to 20 ppm by volume of total product in any phase.

(3) An evaluation at least four times per calendar year, at intervals not to exceed 4 ½ months, to ensure that corrosion-affecting constituents are effectively monitored and mitigated.

(4) An evaluation and review of the monitoring and mitigation program at least once each calendar year, at intervals not to exceed 15 months, updating and adjusting the program based on the results of that evaluation and review as necessary.

XX. In § 195.588, revise its title and paragraphs (c)(4)(i) and (c)(4)(ii) to read as follows:

§ 195.588 Direct assessment standards.

*   *   *   *   *

(c)   *   *   *

(4)   *   *   *

(i) Non-significant SCC, as defined by NACE SP0204–2008, may be mitigated by either hydrostatic testing in accordance with paragraph (c)(4)(ii) of this section, or by grinding out with verification by Non-Destructive Examination (NDE) methods that the SCC defect is removed and repairing the pipe. If grinding is used for repair, the remaining strength of the pipe at the repair location must be determined using ASME/ANSI B31G or RSTRENG (incorporated by reference, *see* § 195.3) and must be sufficient to meet the design requirements of subpart C of this part.

(ii) Significant SCC must be mitigated using a spike hydrostatic testing program in accordance with § 195.309. Any test failures due to SCC must be repaired by replacement of the failed pipe segment, and the segment retested, including the spike portion of the test, until the pipe passes the complete test without leakage. Pipe segments that have SCC present, but that pass the pressure test, may be repaired by grinding in accordance with paragraph (c)(4)(i) of this section.

*   *   *   *   *

XX. In Appendix B to Part 195, revise Table 4 to read as follows:

Appendix B to Part 195 - Risk-Based Alternative to Pressure Testing Older Hazardous Liquid and Carbon Dioxide Pipelines

*   *   *   *   *

Table 4 - Product Indicators

Indicator	Considerations	Product examples
H	Highly volatile and flammable	(Propane, butane, Natural Gas Liquid (NGL), ammonia).

Indicator	Considerations	Product examples
	Highly toxic	(Benzene, high Hydrogen Sulfide content crude oils).
M	Flammable - flashpoint <100F	(Gasoline, JP4, low flashpoint crude oils).
	Asphyxiating	(Carbon dioxide).
L	Non-flammable - flashpoint 100 + F	(Diesel, fuel oil, kerosene, JP5, most crude oils).

* * * * *

XX. In Appendix C to Part 195, revise paragraph I.B.(5) and the "Product Transported" table under section III to read as follows:

Appendix C to Part 195 - Guidance for Implementation of an Integrity Management Program

I. * * *

B. * * *

(5) The nature and characteristics of the product the pipeline is transporting (refined products, crude oils, highly volatile liquids, etc.). Highly volatile liquids, including carbon dioxide, become gaseous when exposed to the atmosphere. A spillage could create a vapor cloud that could settle into the lower elevation of the ground profile.

* * * * *

III. * * *

Product Transported

Safety risk indicator	Considerations[1]	Product examples
High	Highly volatile and flammable	(Propane, butane, Natural Gas Liquid (NGL), ammonia).
	Highly toxic	(Benzene, high Hydrogen Sulfide content crude oils).
Medium	Flammable - flashpoint <100F	(Gasoline, JP4, low flashpoint crude oils).
	Asphyxiating	(Carbon dioxide).
Low	Non-flammable - flashpoint 100 + F	(Diesel, fuel oil, kerosene, JP5, most crude oils).

[1] The degree of acute and chronic toxicity to humans, wildlife, and aquatic life; reactivity; and, volatility, flammability, and water solubility determine the Product Indicator. Comprehensive Environmental Response, Compensation and Liability Act Reportable Quantity values may be used as an indication of chronic toxicity. National Fire Protection Association health factors may be used for rating acute hazards.

*   *   *   *   *

PART 196—PROTECTION OF UNDERGROUND PIPELINES FROM EXCAVATION ACTIVITY

XX. The authority citation for part 196 continues to read as follows:

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

XX. Amend 196.109 to read as follows:

§ 196.109 What must an excavator do if damage to a pipeline from excavation activity causes a leak where product is released from the pipeline?

If damage to a pipeline from excavation activity causes a release from a facility subject to PHMSA regulation under part 192, 193, or 195 of this chapter, the excavator must promptly report the release to appropriate emergency response authorities by calling the 911 emergency telephone number.

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

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

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

XX. In § 198.3, revise the definition of "underground pipeline facilities" to read as follows:

§ 198.3 Definitions.

* * * * *

Underground pipeline facilities means buried pipeline facilities used in the transportation of gas or hazardous liquid (as well as carbon dioxide) subject to the pipeline safety laws (49 U.S.C. 60101 *et seq.*).

* * * * *

XX. In 198.55, revise paragraph (a)(6)(iii)(B) as follows:

§ 198.55 What criteria will PHMSA use in evaluating the effectiveness of State damage prevention enforcement programs?

(a) * * *

(6) * * *

(iii) * * *

(B) If the damage results in the escape of any PHMSA regulated natural and other gas or hazardous liquid (as well as carbon dioxide), must promptly report to other appropriate authorities by calling the 911 emergency telephone number or another emergency telephone number.

* * * * *

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Alan K. Mayberry,

Associate Administrator for Pipeline Safety.