COLORADO DEPARTMENT OF REGULATORY AGENCIES

Public Utilities Commission

4 *CODE OF COLORADO REGULATIONS* (CCR) 723-11

PART 11
RULES REGULATING PIPELINE OPERATORS AND GAS PIPELINE SAFETYBASIS, PURPOSE, AND STATUTORY AUTHORITY

11001. Definitions.

The following definitions apply throughout this Part 11, except where a specific rule or statute provides otherwise or where the context otherwise indicates. In the event of a conflict between these definitions and a statutory definition, the statutory definition shall apply.

(a) "Advanced leak detection technology" means commercially available equipment that can detect leaks in gas pipelines at a detection threshold of a 10 kg/hr emission rate with 90 percent or greater probability of detection, or better, to use with other Part 192-regulated gas pipeline facilities or within a suite of mutually-reinforcing technologies to offer comparable leak detection ability. This can include a variety of commercially available methods to detect leaks including, but not limited to, optical, infrared, or laser-based devices; continuous monitoring via stationary gas detectors, pressure monitoring or other means; mobile surveys; or systemic use of any other commercially available advanced technology.

(b) "Business district" means an area that has pipeline facilities located under predominately continuous paving or concrete that extends:

(I) from the center line of a street to a building wall on one or both sides of the street; or

(II) from a main to a building wall; or

(III) any other area that, in the judgement of the operator, should be so designated.

(c) "C.F.R." means the Code of Federal Regulations.

(d) "Confirmed discovery" means a discovery defined, as of the effective date of these rules, in 49 C.F.R. § 191.3.

(e) "Continuing violation" or "time-dependent violation" means any violation of these rules for which a timeframe of non-compliance can be established through physical evidence and/or records that include, but are not limited to: operator annual reports; operator compliance, operations, and maintenance records; and Commission inspection, compliance and proceeding records.

(f) "Delivered system pressure" means the system operating pressure measured at the outlet of the furthest downstream appurtenance maintained by the pipeline system operator, e.g., regulator, meter, valve, or the terminal connection of the service riser in low-pressure distribution systems.

(g) "De minimis gas system" means a non-utility underground pipeline system used for transport and distribution of natural gas to less than ten customers within a definable private (i.e., non-municipal or public) area (e.g., a mobile home park or resort) and that does not cross a public right-of-way.

(h) "Direct sales meter" means a meter that measures the transfer of gas to a direct sales customer purchasing gas for consumption.

(i) "Direct sales pipeline" means a pipeline not under the jurisdiction of the Federal Energy Regulatory Commission and that runs from an intrastate or interstate transmission pipeline, a production facility, or a gathering pipeline to a direct sales meter, a pressure regulator, or an emergency valve, whichever is the furthest downstream.

(j) "Distribution system" means the piping and associated facilities used to deliver natural gas to customers and does not include the facilities that an operator owns that are classified as production, storage, gathering, or transmission facilities.

(k) "Excavation damage" means any impact that results in the need to repair or replace an underground facility due to a weakening or the partial or complete destruction of a facility, including, the protective coating; plastic pipe tracer wire; lateral support; cathodic protection; or the housing for the line device or facility.

(l) "Gas" means natural gas, flammable gas, and any gas that is toxic or corrosive gas, or petroleum gas.

(m) "Gathering pipeline" means any pipeline determined through the use of 49 C.F.R. § 192.8 to be jurisdictional.

(n) "Geographic Information Systems (GIS)" means a computer-based system for capturing, storing, checking, displaying, and analyzing data related to positions on Earth's surface.

(o) "Hazardous facility" means a pipeline facility that, if allowed to go into operation or to remain in operation, would pose a severe or imminent risk to public safety.

(p) "Inactive/Idle" means a pipeline or pipeline segment that has ceased normal operations and will not resume service for a period of not less than 180 days; has been isolated from all sources of hazardous liquid, natural gas, or other gas; and has been purged of combustibles and hazardous materials and maintains a blanket of inert, non-flammable gas at low pressure or has not been purged but the volume of gas is so small that there is no potential hazard, as defined in 49 U.S.C. § 60143.

(q) "Incident" means an event defined as of the effective date of these rules, in 49 C.F.R. § 191.3, for a pipeline facility covered by 49 C.F.R. Part 192 or an emergency, as defined in § 193.2007 for an LNG facility.

(r) "Liquefied natural gas" (LNG) means natural or synthetic gas that has methane (CH_4) as its major constituent and that has been converted to liquid form for purposes of storage or transport.

(s) "Liquid petroleum gas (LPG) system" means the liquid petroleum (LP) tanks and/or the pipeline system used to transport and distribute LP fuel gas to ten or more customers within a definable private (i.e. non-municipal or public) area (e.g., a mobile home park or resort), or less than ten customers if the system crosses a public right-of-way. LPG systems may have multiple operators if the supplying tank(s) is/are operated and maintained distinctly from the pipeline system by a different owner.

(t) “Low-pressure distribution system” means a gas distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer, i.e., the low-pressure gas burning equipment of the customer may be safely and continually operated at the delivered system pressure.

(u) “LPG Tank – CDLE OPS Inspected” means any LPG tank inspected by the Colorado Department of Labor and Employment, Division of Oil and Public Safety under the authority of the OPS rules.

(v) “LNG facility” means a pipeline facility that is used for liquefying natural or synthetic gas and/or for transferring, storing, or vaporizing liquefied natural gas.

(w) “Main” means a distribution line that serves, or is designed to serve, as a common source of supply for more than one service line.

(x) “Major master meter operator (MMO)/LPG system” refers to any MMO or LPG pipeline system serving 100 or more customers.

(y) “Mechanical excavation” means any operation in which earth is moved or removed by means of any tools, equipment, or explosives and includes auguring, backfilling, boring, ditching, drilling, grading, plowing-in, pulling-in, ripping, scraping, trenching, hydro-excavating, post/postholing, and tunneling.

(z) “MMO gas system” means a non-utility pipeline system used for transport and distribution of natural gas to ten or more customers within a definable private (i.e., non-municipal or public) area (e.g., a mobile home park or resort), or less than ten customers if the system crosses a public right-of-way.

(aa) “Minor MMO/LPG system” means any MMO or LPG pipeline system serving between 20 and 99 customers.

(bb) “Municipality” means a city, town, or village in the state of Colorado.

(cc) “NRC” means the National Response Center of the United States Coast Guard.

(dd) “NTSB” means the National Transportation Safety Board, an independent federal agency.

(ee) “Natural Gas Pipeline Act” means the federal statute found at 49 U.S.C. §§ 60101 et seq., as amended.

(ff) “No immediate safety impact” refers to action or inaction by operator/operator contractors on jurisdiction pipeline facilities that resulted in no immediate or imminent hazard to either the public, operator/operator contractor personnel, or pipeline system integrity.

(gg) “Operator” means a person who is engaged in the transportation of gas, or who has the right to bury underground pipeline, or who is both engaged in the transportation of gas and has the right to bury underground pipeline, and may include an owner, such as a pipeline corporation.

(hh) “Operator contractor” means any person or entity empowered by an operator to perform any action covered by 49 C.F.R. Part 192 and these rules.

(ii) “Operator endangerment” refers to action or inaction by operator/operator contractors on pipeline facilities that resulted in an immediate or imminent hazard to operator/operator contractor personnel.

(jj) “OPS” means the Office of Pipeline Safety, a unit of the PHMSA.

(kk) “Part 192” means 49 C.F.R. Part 192 – Transportation of natural and other gas by pipeline: Minimum Federal safety standards.

(ll) “Person” means an individual, firm, joint venture, partnership, corporation, association, municipality, cooperative association, or joint stock association, and includes any trustee, receiver, assignee, or personal representative thereof.

(mm) “Petroleum gas” means propane, propylene, butane, (normal butane or isobutanes), and butylene or mixtures composed predominately of these gases.

(nn) “PHMSA” means the Pipeline and Hazardous Materials Safety Administration, an agency of the United States Department of Transportation.

(oo) “Pipeline” or “pipeline system” means all parts of those physical intrastate facilities through which gas moves in transportation, including, but not limited to, pipes, valves, and other appurtenances attached to pipes, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies that start downstream beyond the farthest most point of oil and gas production. Flowlines that are regulated by the ECMC and used for oil and gas production are not included in the definition.

(pp) “Pipeline excavation damage prevention program” means an operator’s written program and processes to prevent damage to a pipeline by excavation, as defined in 49 C.F.R. § 192.614.

(qq) “Pipeline facility” means new and existing intrastate pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas, or in the treatment of gas during transportation.

(rr) “Pipeline integrity” means the ability of a pipeline system to operate as it was verifiably designed and constructed.

(ss) “Pipeline safety program” (PSP) means the Commission’s pipeline safety program operated in accordance with the Commission’s 49 U.S.C. §§ 60105 (a) certification and 60106 (a) agreement.

(tt) “Production facility” means flowline and associated equipment used at a wellsite in producing, extracting, recovering, lifting, stabilizing, initial separating, treating, initial dehydrating, disposing, and/or above ground storing, of liquid hydrocarbons, associated liquids, and associated natural hydrocarbon gases. A production facility may include flowlines up to a central delivery point directly associated with a specific producing field. To be a production facility under this rule, a flowline must be used in the process of extracting hydrocarbons and associated liquids from the ground or from facilities where hydrocarbons are produced or must be used for disposal or injection in reservoir maintenance or recovery operations.

(uu) “PSP Chief” means the program manager of the PHMSA certified PSP of the Colorado Public Utilities Commission.

(vv) “PSP Lead Engineer” means the senior technical staff member of the PHMSA certified PSP of the Colorado Public Utilities Commission.

(ww) “PSP Staff” means a staff member of the PHMSA certified PSP of the Colorado Public Utilities Commission.

(xx) “Program certification obligations and agreements” means the pipeline safety program obligations required under 49 U.S.C. § 60105 (a) and the pipeline safety agreements required under 49 U.S.C. § 60106 (b).

(yy) "Public endangerment" means an action or inaction by an operator/operator contractor on pipeline facilities that results in:

(I) interruption or delay of make safe actions designed to protect human life;

(II) unintended gas release requiring emergency (versus precautionary) evacuation of the public;

(III) an unsafe ignition of intended gas release in an area accessible to the public;

(IV) system over pressurization event/failure of system overpressure protection requiring emergency (versus precautionary) evacuation of the public; or

(V) any other hazardous situation that results in an immediate or imminent hazard to the public.

(zz) “Records” means information created, manipulated, communicated or stored in physical, digital, or electronic form. Records relate, but are not limited, to functions, policies, decisions, procedures, operations, or other activities of the utility.

(aaa) “Roadway” means a main public artery, highway, or interstate highway.

(bbb) “Related violation” for purposes of informing the Commission authority pursuant to § 40-7-117, C.R.S., means a violation of these rules that has been proven to be directly linked with a PUC rule violation or violations by time, place, activity, and/or personnel.

(ccc) “Request for Information (RFI)” means any request from the PSP Chief or assignee to a jurisdictional operator for information associated with PSP inspection activities authorized by paragraph 11013(a).

(ddd) "Single structure, above-ground MMO/LPG system" or "SSAG System" means any MMO or LPG system that is:

(I) a low-pressure gas distribution system;

(II) is comprised wholly of above-ground piping/appurtenances; and

(III) is contained wholly within or on a single continuous structure such as an apartment building, hotel, mall, etc.

(eee) "Small operator" means any gas distribution system operator that operates less than 1000 natural gas distribution services in the state of Colorado.

(fff) "Threshold MMO/LPG system" means any MMO or LPG pipeline system serving less than 20 customers.

(ggg) "Transportation of gas" means the gathering, transmission, or distribution, of gas by pipeline, or the storage of gas within the state of Colorado that is not subject to the jurisdiction of the Federal Energy Regulatory Commission under the Natural Gas Act.

(hhh) "UNCC/Colorado 811" means the Utility Notification Center of Colorado.

(iii) "U.S.C." means the United States Code.

11002. – 11007. [Reserved].

11008. Incorporation by Reference.

(a) The Commission incorporates by reference the federal standards for reporting safety-related conditions associated with the transportation of natural gas and other gas by pipeline published in 49 C.F.R. § 191.23 (reporting safety-related conditions), effective May 16, 2022 and § 191.25 (filing safety-related condition reports), effective July 1, 2020. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 191.

(b) The Commission incorporates by reference the federal safety standards for the transportation of natural gas and other gas by pipeline published in 49 C.F.R. Part 192, effective January 15, 2025. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 192.

(c) The Commission incorporates by reference the federal safety standards for liquefied natural gas facilities that are published in 49 C.F.R. Part 193 effective August 6, 2015. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Part 193.

(d) The Commission incorporates by reference the drug and alcohol testing regulations and procedures of PHMSA published in 49 C.F.R. Part 40, effective June 21, 2024 and Part 199 effective, April 23, 2019. This incorporation by reference does not include later amendments to, or editions of, 49 C.F.R. Parts 40 and 199.

(e) The Commission incorporates by reference the NPMS Operator Standards Manual, updated January 2025.

(f) Any material incorporated by reference in this Part 11 may be examined at the offices of the Commission, 1560 Broadway, Suite 250, Denver, Colorado 80202, during normal business hours, Monday through Friday, except for state holidays. Incorporated standards shall be available electronically and provided in certified copies, at cost, upon request. Restrictions on the provision of physical copies due to copyright protections may apply. The Director or the Director's designee will provide information regarding how the incorporated standards may be examined at any state public depository library. The standards and regulations are also available from the agency, organization or association originally issuing the code, standard, guideline or rule as follows: Code of Federal Regulations: www.govinfo.gov/help/cfr.

11009. More Stringent Standards.

In the event of a more stringent rule of the Commission regarding any administrative, enforcement, operations, maintenance, or construction task or reporting requirement of 49 C.F.R. Parts 40, 192, 193, and/or 199 and Commission Pipeline Safety Rules, the Commission's rule shall apply.

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[indicates omission of unaffected rules]

11012. Waiver – Emergency.

(a) An operator may file a petition to request an emergency waiver or variance in situations that require expedited review that is otherwise inconsistent with § 40-2-115, C.R.S., 49 U.S.C. § 60118(d), and the Commission's Rules of Practice and Procedure.

(b) An emergency waiver request will be granted if it is in the public interest, is consistent with pipeline safety, and is necessary to address an actual or impending emergency involving pipeline transportation, including emergencies caused by natural or manmade disasters.

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[indicates omission of unaffected rules]

11100. Submission of Reports and Notices - General.

(a) For all annual reporting, the PSP will access the PHMSA Pipeline Data Mart beginning on March 16 of every year to confirm operator submittals. Failure to meet annual report submittal deadlines will result in issuance in a warning notice; failure to meet submittal deadlines in two successive calendar years will result in the issuance of a NPV against the operator.

(b) For all specialized reporting, failure to meet submittal deadlines and requirements will result in issuance in a warning notice or a NPV against the operator.

(c) Geographic Information System (GIS) data listed in subparagraph (II) below shall be submitted to the PSP. GIS data shall be submitted in the North American Datum of 1983 (NAD 83). Data may be submitted in zipped geodatabase (GDB), zipped shapefile (SHP), or google keyhole markup language (KML), with preference for GDB and SHP.

(I) Data shall be submitted electronically, including through a form available on the Commission's website. Commission staff may update the form periodically. Whether annual filings are provided through the Commission-provided form or separately, operators shall ensure that all information required is included in any submitted report filings.

(II) Data specifications. The following data attributes for transmission, distribution, and gathering pipelines shall be submitted to the extent available:

(A) spatial location of the pipeline;

(B) operator name;

(C) fluid type;

(D) designation of pipeline as transmission, distribution, or gathering;

(E) for transmission pipelines only, the additional data provided to the National Pipeline Mapping System (NPMS) by the operator;

(F) abandoned as defined in 49 CFR 192.3 and inactive pipelines. Include abandonment and inactive dates as applicable, as defined in 49 CFR 192.727;

(G) the maximum allowable operating pressure;

(H) the testing pressure;

(I) the pipe description (i.e., nominal diameter, coating, standard dimension ratio, wall thickness, and material);

(J) description of corrosion protection (i.e., Galvanic, Rectified/Impressed Current, or NA);

(K) identify as HCA/MCA on each segment, as applicable; and

(L) identify class location for each segment as applicable.

(III) Disclosure of GIS data.

(A) The PSP Chief will make the GIS data in subparagraphs (II)(A)-(F) above available through a publicly accessible online map viewer. Online map viewer data only will be available at scales greater than or equal to 1:6,000. Any person may view spatial data at scales less than 1:6,000 for an individual parcel at the Commission’s office, with the exception of map viewer data filed confidentially. Any data provided confidentially must be filed with a publicly accessible version at a scale greater than or equal to 1:24000.

(B) Upon request from a local governmental designee(s), and subject to executing a confidentiality agreement and the provisions of the Colorado Open Records Act and applicable federal law, the Commission will allow the local government to view in the Commission’s offices the GIS data (including the data described in subparagraphs (II)(G)-(J) above) for transmission, distribution or gathering pipeline systems within the Commission’s jurisdiction. The local government may only reproduce or publish data that the Commission makes publicly available through its website. A local government may share more specific data in-person than that which the Commission makes publicly-available, but the information must be treated as confidential and may not be reproduced or published.

(C) Except as provided in subparagraphs (III)(A) and (B) above, the Commission will keep all such GIS data confidential to the extent allowed by the Colorado Open Records Act.

(D) This data will not be used in lieu of Colorado 811 locates and is subject to civil penalties set forth in and fines assessed pursuant to §§ 9-1.5-104.4 or 9-1.5-104.5, C.R.S.

(d) For all electronic reporting to PHMSA, if this reporting method imposes an undue burden and hardship, an operator may submit a written request for an alternative reporting method to: Information Resources Manager, Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, PHP-20, 1200 New Jersey Avenue, SE, Washington, DC 20590. The request must describe the undue burden and hardship. PHMSA will review the request and may authorize, in writing, an alternative reporting method. An authorization will state the period for which it is valid, which may be indefinite. An operator must contact PHMSA at 202-366-8075; electronically to informationresourcesmanager@dot.gov; or make arrangements for submitting a report that is due after a request for alternative reporting is submitted but before an authorization or denial is received.

(e) Annual leak report.

(I) Beginning March 31, 2025 and annually on March 31 of each year thereafter, each operator must submit a report to the Commission that includes:

(A) the total number of known pending leaks, excluding those repaired in pipelines owned by the operator as of January 1st of the year the report is submitted;

(B) the total number of hazardous leaks, as defined by DOT F7100.1-1 reporting instructions, eliminated or repaired during the previous one-year period ending December 31st;

(C) the total number of nonhazardous leaks eliminated or repaired during the previous one-year period ending December 31st;

(D) the total number of leaks scheduled for repair in the next one-year period beginning January 1st of the year the report is submitted;

(E) the approximate date and location of each identified leak from the gas pipeline system detected by the operator through leak survey and pending as of January 1 of the reporting calendar year;

(F) for repaired leaks, the material type of the pipe and facility that was leaking;

(G) the leak survey method(s) used to detect each pending leak;

(H) the approximate date and location of each leak caused by third-party excavation;

(I) the volume of each leak, measured in millions of cubic feet, except that where an exact volume of gas leaked cannot be identified, an operator may provide its best approximation, if available, and narrative explanation of its calculations and regarding it estimation;

(J) whether the identified cause of each repaired leak was from: corrosion failure; natural force damage; excavation damage; other outside force damage; pipe, weld, or joint failure; equipment failure; incorrect operations; or other causes;

(K) the written analysis of its selection of advanced leak detection technologies for each leak survey conducted in the prior calendar year in accordance with paragraph 11209; and

(L) for each gas leak, the leak classification, the confirmed discovery date, the latest leak evaluation date, and the expected or actual repair date.

(II) Natural gas leaks include all confirmed discoveries of unintentional leak events, including leaks from: corrosion failure; natural force damage; excavation damage; other outside force damage; pipe, weld, or joint failure; equipment failure; incorrect operation; or other causes.

(III) The Commission may use the data reported by operators under this section, as well as other data reported by operators to the Commission and to the Air Pollution Control Division and spill and incident data reported by operators to Carbon and Energy Management Commission to estimate the volume of leaked gas and associated greenhouse gas emissions from operational practices in the state. The Commission may request additional information.

(IV) The data provided in this section, including the total number of leaks scheduled for repair under subsection 11100(e)(I)(D), does not prevent the operator from prioritizing its repair schedule based on new information and newly identified leaks.

(f) Disclosure of leak detection data.

(I) By June 1, 2025 and annually on June 1 of each year thereafter, the Commission will provide on its public internet website aggregate data, as submitted by operators under this section, concerning the volume and causes of gas leaks.

(II) By June 1, 2025 and annually on June 1 of each year thereafter, the Commission will transmit to the Air Pollution Control Division and Energy and Carbon Management Commission information on gas leakage in the state, as submitted by operators under this rule.

11101. Submission of Reports and Notices.

(a) Operators must submit all required reports, as applicable, within the specified deadline(s) for the following occasions requiring specialized reporting or notice. Any reporting shall be in addition to, or supplemental to, reporting required under federal law and shall not be duplicative.

(b) Incident reporting.

(I) Written reports of all incidents required to be reported under these rules must be submitted as soon as practicable but not more than 30 days after detection of the incident.

(II) Each operator submitting information to PHMSA via its electronic portal shall also file such information with the Commission in accordance with subparagraph 1204(a)(III) of the Commission's Rules of Practice and Procedure in the repository proceeding opened for such reporting purpose.

(III) Each operator that submits information to PHMSA via alternative methods shall file copies of this information with the Commission.

(IV) Each operator of a distribution pipeline system, excepting MMO/LPG systems, shall submit the Incident Report (PHMSA F 7100.1) to PHMSA using its electronic portal at https://portal.phmsa.dot.gov.

(V) Each operator of an MMO/LPG system shall submit a Small Operator Incident Report (PSP SOIR) to the Commission through its E-Filings System in the repository proceeding opened for such reporting purposes.

(VI) Each operator of a transmission or gathering system (Types A, B, and C), shall submit the Incident Report (PHMSA F 7100.2) to PHMSA using its electronic portal at https://portal.phmsa.dot.gov.

(VII) Each operator of a LNG facility shall submit the Incident Report (PHMSA F 7100.3) to PHMSA using its electronic portal at https://portal.phmsa.dot.gov.

(VIII) When additional relevant information is obtained after the report is submitted under paragraph (a) or (b) of this rule, the operator shall make supplementary reports as deemed necessary with a clear reference by date and subject to the original report. The operator shall notify the PSP Chief of all supplementary reporting.

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[indicates omission of unaffected rules]

11102. Verbal Reporting of Pipeline Incidents and Events.

(a) Colorado pipeline incidents.

(I) All pipeline and LNG facility operators must provide expedited reporting of a pipeline incident as soon as possible after confirmed discovery; not to exceed two hours after confirmed discovery.

(II) If the expedited reporting time for a pipeline incident exceeds two hours after confirmed discovery, the operator shall provide a written explanation for the time exceedance to the PSP Chief within ten business days after the incident.

(III) All operators must report a pipeline incident to:

(A) the NRC via telephone at 800-424-8802; and

(B) after an NRC control number is issued for the incident, to the PSP Staff via telephone at 303-894-2854.

(IV) A telephonic report made pursuant to this rule must include the following information:

(A) the NRC control number;

(B) the name and telephone number of the operator and the contact for more information on the incident;

(C) the location of the incident or event;

(D) the date and time of the incident or event;

(E) the number of fatalities and personal injuries, if any; and

(F) all other significant facts that are known by the person making the report that are relevant to the cause of the incident and the extent of the damage.

(b) Colorado pipeline events.

(I) All pipeline operators, including operators of LNG facilities/systems and MMO/LPG systems, must provide expedited reporting of pipeline events described below as soon as possible after discovery; not to exceed two hours after confirmed discovery.

(II) If the expedited reporting time for a pipeline event exceeds two hours after confirmed discovery, the operator shall provide a written explanation for the exceedance to the PSP Chief within ten business days after the event.

(III) All pipeline operators must report the following pipeline events to the PSP Staff via telephone at 303-894-2854:

(A) an unplanned/emergency event that occurs on the pipeline system that results in the evacuation of 50 or more people from a normally occupied building or property;

(B) an unplanned/emergency event that occurs on the pipeline system that results in the closure of all lanes in either direction of a roadway or railroad;

(C) an unplanned/emergency event that occurs on the pipeline system that results in the evacuation of four or more residential structures;

(D) an unplanned/emergency event that occurs on the pipeline system that results in a service outage of 100 or more customers;

(E) an event that requires active soil vapor extraction for a period exceeding 48 hours as measured from the time the extraction device is turned on at the site until the operator determines soil vapor extraction is no longer necessary;

(F) a MAOP-exceedance event that requires the operator, pursuant to its procedures, to implement follow-up actions such as a leak survey; or

(G) an event that, in the opinion of the operator, requires courtesy notification to the PSP.

11103. Submission of Annual Reports.

(a) On or before March 15 of each year:

(I) each operator of a distribution pipeline system, excepting MMO/LPG systems, shall submit the annual report (PHMSA F 7100.1-1) to PHMSA using its electronic portal at https://portal.phmsa.dot.gov;

(II) each operator of an MMO/LPG system shall submit the MMO/LPG annual report to the Commission through its E-Filings System in the repository proceeding opened for annual reports;

(III) each operator of a transmission or gathering system (i.e., Types A, B, C, and R), shall submit the annual report (PHMSA F 7100.2-1 or PHMSA F7100.2-3, as appropriate) to PHMSA using its electronic portal at https://portal.phmsa.dot.gov; and

(IV) each operator of a LNG facility shall submit the annual report (PHMSA F 7100.3-1) to PHMSA using its electronic portal at https://portal.phmsa.dot.gov.

(b) On or before March 31, 2025, and March 31 of each year thereafter:

(I) each operator shall submit to the Commission GIS data according to paragraph 11100(c); and

(II) each operator shall submit to the Commission a list of leak detection tools, techniques, methods, and processes, including narrative of any advanced leak detection technologies, being used along with the extent of their use and their descriptions according to paragraph 11100(e).

11104. – 11199. [Reserved].

SAFETY STANDARDS FOR HAZARDOUS GAS PIPELINE SYSTEMS

11200. Standards – General.

An operator shall comply with these rules and the minimum safety standards for the transportation of natural gas and other gas by pipeline that are incorporated by reference in rule 11008, as applicable.

11201. Pipeline Excavation Damage Prevention.

(a) All operators must be members of the UNCC/Colorado 811 if any part of the pipeline system is located in any public or railroad right-of-way.

(b) All operators, excluding operators of MMO/LPG pipeline systems, must report underground facility damages to the UNCC/Colorado 811 in accordance with § 9-1.5-103(7), C.R.S.

(c) Operators of MMO/LPG must install and maintain pipeline markers, labeled according to § 192.707(d), at each crossing of a public road or railroad right-of-way.

(d) All operators, excluding operators of MMO/LPG, must have written guidelines regarding when and how civil penalties are pursued under § 9-1.5-104.5, C.R.S. against persons damaging their pipeline facilities, and when and how penalty alternatives are implemented. At a minimum, the collection of data on and subsequent analysis of the causes of excavation damages to comply with 49 C.F.R. § 192.614 (a). These guidelines must provide for:

(I) recording information about pipeline damages that includes identification of the responsible party and the probable cause of each excavation damage in the following categories:

(A) inadequate excavation practices;

(B) no locate requested;

(C) inaccurate/missing locate – Operator located; and

(D) inaccurate/missing located – Contractor located.

(II) Analysis of the information in (a) above that allows for the identification of acute risk parties that have caused multiple pipeline damages in the preceding 18 months; and

(III) analysis of the information in (a) above that allows for the identification of chronic risk parties that have caused multiple pipeline damages over (a) time period(s) greater than 18 months.

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[indicates omission of unaffected rules]

11203. Small Operator Systems.

(a) General requirements.

(I) Unless otherwise specified in this rule, a small operator system is subject to these rules and all applicable 49 C.F.R. Part 192 rules, as incorporated.

(II) Unless otherwise specified in this rule, any operator of a small operator system may opt into the prescriptive distribution integrity management provisions of paragraph (h) of this rule via written request to the PSP Chief or PSP Lead Engineer.

(b) Standards applied to de minimis gas systems.

(I) Unless otherwise specified in this rule, de minimis gas systems are exempt from these rules and 49 C.F.R. Part 192 rules, as incorporated.

(II) System expansion.

(A) Operators of de minimis gas systems must apply for Commission approval prior to any system expansion.

(B) Operators of de minimis gas systems are prohibited from expanding the system unless proper permits are issued by the appropriate plumbing inspection authority.

(III) Leak surveys.

(A) De minimis gas systems must be leak surveyed with equipment using instruments and techniques suitable for detecting fugitive natural gas, or LPG in gaseous/vapor form, as applicable, once every two years.

(B) Records and results of all leak surveys will be kept for the life of the system.

(IV) System repairs.

(A) An operator of a de minimis gas system must repair all pipeline leaks that represent an existing or probable hazard to persons or property immediately upon discovery.

(B) An operator of a de minimis gas system must repair all other pipeline system leaks within 45 days of discovery.

(C) All system repairs must be completed by a plumber, gas utility technician, or utility contractor qualified to install and repair underground gas systems.

(D) Prior to any leak repair, the operator of a de minimis gas system must acquire a plumbing permit issued by the appropriate plumbing inspection authority. If a leak has been repaired immediately due to a public safety hazard, the repair must be permitted after the fact and will be left exposed for inspection by the appropriate plumbing inspection authority or a PSP Inspector.

(c) Standards applied to SSAG systems.

(I) Any SSAG system is compliant with these rules if the system has been inspected and passed a system safety inspection within the last five years by one of the following means:

(A) inspection by the PSP;

(B) inspection by the Fire Department or Fire Marshall using NFPA 54 (National Fuel Gas Code), NFPA 101 (Life Safety Code), or a written equivalent standard; or

(C) inspection by the plumbing entity using the International Fuel Gas Code or a written equivalent standard.

(II) Record of the final, approved inspection of the gas system installation shall be kept for the life of the system.

(III) Records of all subsequent inspections shall be maintained and available for PSP inspection for a minimum of ten years from the date of inspection.

(d) Standards applied to LPG systems.

(I) The PSP will deem any LPG tank – CDLE OPS Inspected to be compliant with these rules, subject to the following restrictions:

(A) the tank has passed the CDLE OPS inspection; and

(B) the tank has been inspected within the last five calendar years.

(II) Leak surveys and leak pinpointing must use instruments and techniques suitable for detecting fugitive LPG in gaseous/vapor form.

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[indicates omission of unaffected rules]

11209. Advanced Leak Detection Survey Requirements.

(a) Operators must select advanced leak detection technology by considering, at a minimum, the following criteria and must provide a written analysis of the selection in accordance with subparagraph 11101(e)(I)(K):

(I) the state of commercially available leak detection technologies and practices;

(II) the ability of leak detection technologies to estimate the leak rate;

(III) the size and configuration of the pipeline system; and

(IV) the system operating parameters and environment.

(b) Leak detection survey. In addition to the requirements incorporated by reference in paragraph 11008(b), an operator shall comply with the following subparagraphs. Operators shall perform all leak detection surveys with the use of advanced leak detection technology equipment**,** as appropriate for each specific survey**,** and identified in subparagraph 11103(b)(II) annual reporting requirement.

(I) Transmission pipelines.

(A) For transmission pipelines in Class 1, 2, 3, or High Consequence Area (HCA), an operator shall perform a leak detection survey at intervals not exceeding seven and a half months, but at least twice each calendar year.

(B) For transmission pipelines in Class 4 areas, an operator shall perform a leak detection survey at intervals not exceeding four and a half months, but at least four times each calendar year.

(II) Distribution pipelines.

(A) For distribution pipelines inside business districts, operators shall follow the requirements listed in 49 CFR 192.723.

(B) For distribution pipelines outside of business districts that have steel pipelines without cathodic protection, are known to leak based on material, design, or past operations and maintenance history, or are distributed anode protected pipelines with an historically deficient reading, operators shall perform a leak detection survey at intervals not to exceed 15 months but at least once a calendar year or as close to once a calendar year as practicable after environmental conditions that may affect venting or gas migration resolve, until the deficiency is remediated.

(C) For all other distribution pipelines outside of business districts, operators shall perform a leak detection survey at intervals not to exceed 39 months, but at least once every three calendar years.

(D) Small Operator Systems are exempt from this section.

(III) Gathering pipelines.

(A) For gathering pipelines in Class 1, 2, and 3 areas, an operator shall perform a leak detection survey at intervals not exceeding seven and a half months, but at least twice each calendar year.

(B) For gathering pipelines in Class 4 areas, an operator shall perform a leak detection survey at intervals not exceeding four and a half months, but at least four times a year.

11210. Leak Classification and Repair Requirements.

(a) Effective January 1, 2027, each operator shall inspect and classify all reports of gas leaks within two hours of confirmed discovery. Each operator shall estimate the leakage rate of a gas leak within 48 hours of confirmed discovery using reasonably available information and shall change the leak classification as appropriate.

(I) Leak classification should utilize the following definitions.

(A) Grade 1 – A leak that represents an existing or probable hazard to persons or property, requires immediate repair or continuous action until the conditions are no longer hazardous.

(B) Grade 2 – A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard. Grade 2 leaks include:

(i) any leak with an estimated leakage rate of 5kg per hour or more;

(ii) any leak of LPG, hydrogen gas, or carbon dioxide; and

(iii) any leak that, in the judgement of operating personnel at the scene, is of sufficient magnitude to justify scheduled repair within six months or less.

(C) Grade 3 – A leak that is non-hazardous at the time of detection and is reasonably expected to remain non-hazardous. Grade 3 leaks include:

(i) any leak that does not meet the criteria of Grades 1 or 2; and

(ii) any reading of gas outside of the pipe.

(b) Effective January 1, 2027, minimum requirements for response to each grade of leak are as follows.

(I) A Grade 1 leak requires immediate repair or continuous action until the conditions are no longer hazardous.

(II) A Grade 2 leak shall be repaired within six months after confirmed discovery. When the ground is frozen or otherwise inaccessible, the Grade 2 leak shall be monitored and evaluated at least every 3 months after confirmed discovery to ensure that the leak will not become a Grade 1 leak prior to repair, and shall be repaired within 12 months after confirmed discovery.

(III) A Grade 3 leak shall be monitored and evaluated at least every six months after confirmed discovery to ensure the leak will not become a Grade 1 or Grade 2 leak prior to repair or abandonment, as applicable.

(A) If the pipeline is not scheduled for abandonment within five years of the confirmed discovery date, the leak shall be repaired within 24 months after confirmed discovery.

(B) If the pipeline is scheduled for abandonment within five years of the confirmed discovery date, the operator may monitor and evaluate the leak at least every 6 months instead of repairing.

(IV) A repair can include repair, replacement, or abandonment.

(V) Small operators shall classify all leaks as Grade 1 and repair immediately.

11211. – 11299. [Reserved].

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[indicates omission of unaffected rules]