Department of Regulatory Agencies, Public Utilities Commission

Gas Pipeline Safety Program

Performance Audit
May 2023
2256P



1525 Sherman Street, 7th Floor • Denver, Colorado 80203-1700 • 303.869.2800 • osa.ga@coleg.gov • www.colorado.gov/auditor

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May 31, 2023

Members of the Legislative Audit Committee:

This report contains the results of a performance audit of the Gas Pipeline Safety Program that is administered by the Public Utilities Commission within the Department of Regulatory Agencies. The audit was conducted pursuant to Section 2-3-103, C.R.S., which authorizes the State Auditor to conduct audits of all departments, institutions, and agencies of state government, as well as Section 2-7-204(5), C.R.S., which requires the State Auditor to annually conduct performance audits of one or more specific programs or services in at least two departments for purposes of the SMART Government Act. The report presents our findings, conclusions, and recommendations, and the responses of the Public Utilities Commission and Department of Regulatory Agencies.

Kerri L. Hunter

1525 Sherman Street, 7th Floor • Denver, Colorado 80203-1700 • 303.869.2800 • osa.ga@coleg.gov • www.colorado.gov/auditor

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Key Concern

In Calendar Years 2017 to 2022, the Gas Pipeline Safety Program (Program) administered by the Public Utilities Commission (PUC), within the Department of Regulatory Agencies (Department), did not sufficiently follow federal and state requirements, or legislative intent, to help ensure gas pipeline safety in Colorado. This audit identified pervasive problems in each area of Program operations reviewed, signifying the need for improved processes, systems, management, and oversight.

Key Findings

- The Program did not inspect operators or have records to show it inspected in line with required 1- to 5-year timeframes in 2017 to 2022, did not meet federal inspection metrics, and had missing or incomplete inspection records. 13 of 15 Program inspectors lacked required training and supervision, and 3 of them inspected their most recent former operator employers immediately after being hired at the PUC.
- The Program did not enforce safety requirements for 5,280 of 5,643 (94 percent) instances of operator noncompliance that inspectors identified in 2017 to 2022. The Program gave some verbal warnings to operators, including for accidents resulting in casualties, and did not always follow up to ensure that operators fixed safety issues.
- In 2017 to 2022, the Program assessed only 23 penalties for operator noncompliance—most to small private operators—and collected only 4 penalties. The PUC has not updated state regulations to implement the penalty amounts required by federal regulations and state statute.
- The Program lacked evidence that operators reported gas pipeline safety accidents as required, and that the Program investigated 75 accidents occurring in 2017 to 2021. The Program had incomplete records for 219 accident investigations in 2021 and 2022, with 84 percent lacking evidence of an on-scene accident investigation.
- The Program misreported key information to PHMSA for 2019 to 2022, such as the number of gas pipeline accidents in Colorado, compliance actions taken against operators, and untrained inspectors who lacked supervision.
- The Program has not tracked complaints received about gas pipeline safety and operators, and did not appear to resolve complaints or consider them when planning inspections or approving operator rate increases.

Background

- Natural gas and propane (gas) are used for heating homes/businesses, cooking, and industry. Gas is highly combustible and transported to consumers through pipelines.
- The federal Pipeline and Hazardous Materials Safety Administration (PHMSA) sets safety requirements for gas pipelines, approves states to administer gas pipeline safety programs, and awards federal grants to state programs as long as they enforce and comply with federal requirements.
- Colorado's Gas Pipeline Safety Program regulates intrastate operators of gas pipelines, facilities, and storage. Program duties include inspecting operators, issuing compliance actions and penalties for operator noncompliance with safety requirements, investigating safety accidents, and reviewing public complaints.
- In 2022, the Program had 14 management and staff, and received about $1.6 million in federal grants and State funds. That year, the Program inspected 43 public operators, which serve more than 100 customers, such as Colorado Springs Utilities and Xcel Energy, and inspected 18 private operators, which serve fewer than 100 customers and are often apartment complexes and mobile home parks.

Audit Recommendations Made

39

PUC/Department Responses

Agree: **38**

Partially Agree: **1**

Disagree: **0**

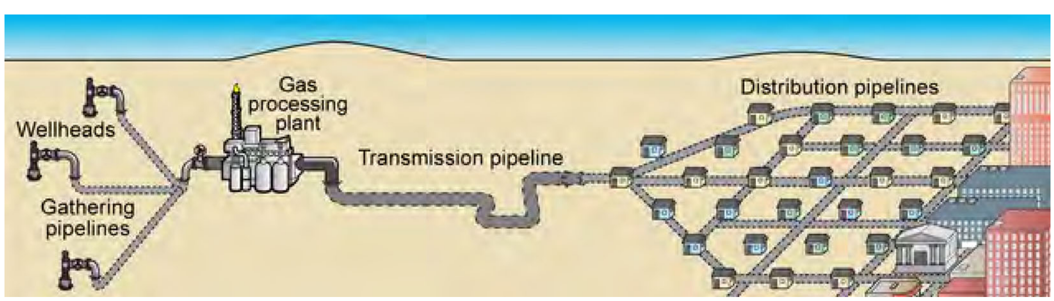
Chapter 1
Overview

Background—Natural Gas and Propane Pipeline Infrastructure and Safety

Natural gas accounts for more than 99 percent of all gas distributed in the United States [U.S. Government Accountability Office (GAO), *Gas Pipeline Safety*, April 2018]. Propane is a byproduct of natural gas processing and petroleum refining. Natural gas and propane—collectively referred to as "gas" in this report—can be used for heating homes and businesses, cooking, and industrial applications, and are highly combustible and easily ignited by heat or sparks [Pipeline Association for Public Awareness, *Newsletter*, Summer 2022].

Pipelines primarily move gas from a utility operator (operator) or a storage facility to residential, commercial, and industrial consumers. As shown in Exhibit 1.1, there are three main types of pipelines—**gathering pipelines** carry gas from a production well to a processing facility or a transmission pipeline, and **transmission pipelines** carry gas to **distribution pipelines** that transport the gas to homes and businesses. Gathering and distribution pipelines tend to be intrastate, meaning they transport gas *within* a state's borders. Transmission pipelines tend to be interstate, meaning they transport gas *across* state boundaries [GAO, *Pipeline Safety,* January 2022; and *Gas Pipeline Safety,* April 2018].

Exhibit 1.1
Gas Pipeline Infrastructure



Source: U.S. Government Accountability Office, *Gas Pipeline Safety*, GAO-18-409.

According to the Colorado Public Utilities Commission (PUC) website, gas pipelines exist almost everywhere—in and between towns, in neighborhoods, and in rural areas, such as near waterways, roads, and railway crossings. Some pipelines are visible above ground and some are buried underground. Examples of gas pipelines are shown in Exhibit 1.2.

Exhibit 1.2
Examples of Buried and Unburied Pipelines

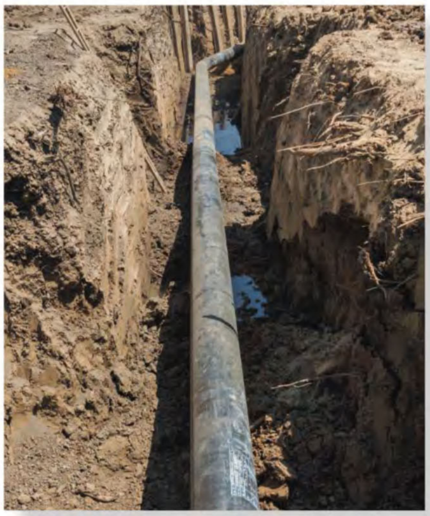


Photo Credit: Shutterstock

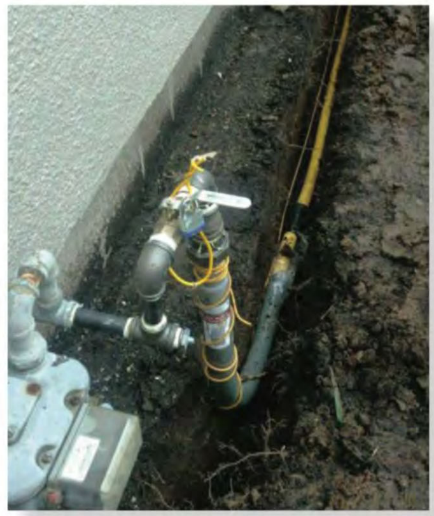


Photo Credit: Industry Image

Photo Credit: Jenny Page

Photo Credit: Jenny Page

Pipeline Safety Programs

In order for natural gas and propane to get to homes and businesses safely, pipelines and related infrastructure must be safe and reliable. Although pipeline systems are considered an efficient and relatively safe means of transporting gas, pipelines are vulnerable to accidents—such as pipeline ruptures and uncontrolled releases of gas—which are also referred to as incidents or events by the gas pipeline industry and regulators [Congressional Research Service (CRS), *Department of Transportation's* (DOT) *Federal Pipeline Safety Program*, March 2023]. The causes of accidents vary, but can include excavation and construction that damages a pipeline, pipeline corrosion, mechanical failure, operator error, natural causes such as floods and earthquakes, and malicious acts. These accidents can injure or kill people, and/or damage property and the surrounding environment [GAO, *Pipeline Safety*, January 2022; and CRS, *DOT's Federal Pipeline Safety Program,* March 2023]. For example, in the United States each year, an average of about 29 serious pipeline accidents involving a fatality or injury requiring hospitalization are reported, and these accidents cause an average of 12 deaths and 58 injuries [CRS, *DOT's Federal Pipeline Safety Program,* March 2023]. According to the PUC's website, to reduce the risk of pipeline damage due to excavation or construction, operators typically use markers such as signs or stakes to mark a pipeline's location; the markers do not show the exact depth, pressure, or number of pipelines.

To help ensure that pipelines are safe, the Pipeline and Hazardous Materials Safety Administration (PHMSA), within the U.S. Department of Transportation, sets and enforces minimum federal safety regulations related to gas pipelines [49 CFR 171 through 180]. PHMSA administers a national pipeline safety program designed to protect the public, property, and environment from the risks posed by the pipeline transportation of natural gas and other hazardous materials. PHMSA is primarily responsible for (1) developing and issuing safety regulations for gas pipelines, their facilities, and storage, and (2) ensuring regulations are enforced. However, the *Natural Gas Pipeline Safety Act of 1968* [49 USC 60101, et seq.] and federal regulations [49 CFR 198.11] allow states to enact intrastate pipeline safety programs, as long as PHMSA approves the state to administer such a program through an annual certification. A state's certification with PHMSA requires state adoption and enforcement of applicable federal safety regulations to help ensure the safe and secure transportation of gas through the intrastate pipelines that operate within its borders [49 USC 60105 and 49 CFR 171.1]. States may issue more stringent safety regulations for intrastate pipelines, as long as the state regulations are compatible with federal regulations. PHMSA develops guidelines, titled *Guidelines for States Participating in the Pipeline Safety Program* (PHMSA Guidelines), which states must follow when administering their programs.

PHMSA annually evaluates each state's pipeline safety program to ensure that states enforce operators' adherence to federal safety regulations as well as follow PHMSA Guidelines [PHMSA Guidelines 2018 through 2022, 2.1 and 8.1]. PHMSA evaluations assess state programs in areas such as:

- Quality of pipeline inspections
- Inspection days completed
- Quality of enforcement and compliance actions taken against operators for noncompliance
- Number of inspectors, and their training and qualifications
- Adoption of federal regulations and guidelines

PHMSA also reviews information on pipeline safety accidents and investigations that have occurred within the state. PHMSA requires operators to report pipeline safety accidents to the National

Response Center (NRC), which is a part of the federal National Response System, and requires state programs to investigate accidents within their intrastate jurisdiction.

Pipeline Regulation in Colorado

The regulation of natural gas and propane transportation in Colorado is primarily divided between the PUC, within the Department of Regulatory Agencies (Department), and the Colorado Oil and Gas Conservation Commission, within the Department of Natural Resources. The PUC is responsible for regulating all intrastate transmission and distribution pipelines from the processing facility to the customer meter. The PUC also regulates operators to ensure that they are safe and reliable, and that the rates they charge serve the economic and environmental needs of the people of the State [Sections 40-1-101, et seq., and 40-2-108, C.R.S.]. The Colorado Oil and Gas Conservation Commission is responsible for regulating gas transportation from the point of production to a PUC-regulated pipeline or facility. The gas piping within a home or business is regulated by local city and county building codes. This performance audit only reviewed the PUC's pipeline safety regulatory functions.

Colorado's Gas Pipeline Safety Program

The focus of this audit was the Gas Pipeline Safety Program (Program), which was created within the PUC in 1993, as Colorado's federal-state program that enforces federal pipeline safety requirements promulgated under federal law [Section 40-2-115(1)(b), C.R.S.]. The Program regulates intrastate gas pipeline operators under a federal certification agreement with PHMSA, and annually applies for the federal Pipeline Safety Program Base Grant (Assistance Listing No. 20.700).

The Program regulates two types of operators in Colorado [Section 40-2-115(c), C.R.S., and PHMSA website], as follows:

- **Public operators, which include municipalities serving more than 100 customers using multiple regulated gas sources.** In Calendar Year 2022, there were 43 public intrastate operators in Colorado. As shown in Appendix A, examples of public operators include Black Hills Energy, the City of Colorado Springs (i.e., Colorado Springs Utilities), and Xcel Energy - Public Service Company of Colorado. The public operators also supply private operators with gas, which the private operators then provide to their customers, as described below.

- **Private operators, including operators of master metered systems or liquid propane gas distribution systems, serving fewer than 100 customers from a single gas source.** In Calendar Year 2022, there were at least 22 private operators in Colorado, which typically serve small areas such as apartment complexes and mobile home parks. Appendix A lists the private operators.

Program Responsibilities

The Program's internal guidelines specify that "the administrative management of the program in accordance with [federal law] is mission critical" and "the mission of the [State's] Gas Pipeline Safety Program is threefold:

- Through a **systematic inspection structure**, the [Program] will understand the direct, indirect, and relative risks posed to public safety by the construction, operation, and maintenance of jurisdictional intrastate hazardous gas pipeline systems in Colorado;

- Through a **systematic evaluation structure**, the [Program] will determine the efficacy of jurisdictional operators' procedures, processes, and actions in minimizing public safety risks associated with these systems; and

- Through a **systematic compliance structure**, the [Program] will take the role of pipeline safety advocate in front of [PUC], advocating for risk-minimizing changes to operator procedures, processes, and actions and/or the punitive assessment of penalties."

This mission that is stated in the Program's internal guidelines aligns with the requirements in PHMSA's Guidelines.

The Program's key responsibilities that this audit reviewed are as follows:

- **Inspect Operators.** Program inspections review operators' compliance with federal and state requirements to help ensure public safety. The Program conducts onsite field inspections, such as inspections of operator equipment and operations, and conducts remote inspections, such as inspections of operator records, safety policies and plans, equipment testing, and maintenance plans. Inspections review different operator units, such as different types of equipment and gas pipelines (e.g., distribution pipelines), within each region in the state where an operator provides service. Inspections are required every 1 to 5 years, depending on the operator unit being inspected, and may need to be conducted more frequently based on an operator's safety risk, such as the number of operator accidents, public complaints, or noncompliance. As part of its inspection responsibilities, Program management must ensure that inspectors are trained and have the knowledge and qualifications to conduct the types of inspections that they are assigned. According to Program records, in Calendar Year 2022, the Program employed 12 full-time and part-time inspectors who conducted various types of inspections of 102 operator units for the 43 public operators, and 52 inspections of various types for 18 of the 22 private operators of master metered systems.

- **Enforce Safety Regulations and Standards.** When a Program inspection or investigation (described below) finds that an operator has not satisfactorily complied with pipeline safety requirements, the Program may issue the operator a compliance action that is intended to remediate and prevent recurrence of violations. Examples of violations that the Program may identify include an operator's inadequate management of safety records; technical operator error, such as not performing required repair of a known gas leak; and inadequate safety procedures or plans, such as lack of a plan to address an emergency. For compliance actions, the Program typically uses warnings and notices of probable violations that direct operator compliance or corrective action. The PUC may also assess a civil penalty (penalty) to an operator for noncompliance. According to PUC management, its Fixed Utilities Section works with the Commissioners to approve some operators' plans for investing in safety-related improvements in the state; however, the Program's operations are separate from the Fixed Utilities Section and, as such, that Section was outside the scope of this audit. According to PUC and Program records, in Calendar Year 2022, the Program issued 16 operators a total of 17 compliance actions; this included assessing operators $4.8 million in penalties and collecting $5,000 in penalties.

- **Investigate Safety Accidents.** The Program is required to investigate accidents that operators report to the Program and the NRC to determine jurisdiction, culpability, and any resulting action needed to ensure that the operator complies with federal and state safety requirements. Accidents vary, but generally include a gas release that results in an unintentional fire or explosion, death or injury, significant property damage, an emergency shutdown of a facility, and/or evacuation of a large number of people. According to Program records, in Calendar Year 2022, the Program investigated 107 gas pipeline safety accidents.

- **Complaint Management and Follow-up.** The Program is responsible for receiving and resolving complaints related to the gas pipelines and operators within its jurisdiction. For example, individuals may send the Program complaints about operators or pipelines that may not appear safe. The PUC has the authority to issue a corrective action or penalty to an operator if the Program finds that the complaint relates to operator noncompliance with a safety violation. The audit identified five complaints that the Program appeared to receive in Calendar Years 2018 through 2021.

- **Federal Reporting.** The Program reports key information on its operations to PHMSA as part of the Program's pipeline inspection certification, which grants Colorado the authority to administer a gas pipeline safety program on behalf of the federal government, if the State consistently meets federal standards [49 USC 60105]. Examples of information that the Program reports to PHMSA annually on grant applications and progress reports include the number of inspection days completed, the compliance actions taken to enforce operator compliance with safety requirements, and gas pipeline safety incidents/accidents in the state. The Program also tracks and reports certain information in PHMSA's federal system, Inspection Assistant (IA).

Program Administration

In Calendar Year 2022, the Program employed 14 management and staff, including a Lead Engineer who serves as the senior technical staff member who is a pipeline safety subject matter expert, and a Program Manager who manages the day-to-day operations of the Program. As discussed later in the report, the Program Manager was relatively new to the PUC when we began our audit in July 2022, having started working for the PUC in April 2021 after the former Program Chief/Manager retired.

The PUC is overseen by a Director who is hired by the Department's Executive Director, with input from three Governor-appointed Commissioners [Sections 40-2-101 and 103, C.R.S.]. The Commissioners promulgate state regulations/rules related to pipeline safety, with input from Program staff; make certain regulatory decisions, such as approving operator penalties that Program staff recommend during proceedings or proceeding hearings; and review and approve operator requests for changes to the rates that operators charge natural gas and propane customers. According to statute, the regulations/rules that are promulgated by the PUC "must apply to all persons and entities constituting the intrastate pipeline system to the maximum extent permissible under federal law and the Colorado Constitution" [Section 40-2-115(1)(c), C.R.S.]. During the audit in November 2022, the PUC Director retired, and the Department's Executive Director appointed an interim Director to temporarily fill the position until May 2023, when the Department hired the new PUC Director.

The PUC is a type-1 entity within the Department, meaning the Commissioners generally exercise their powers and duties to regulate and promulgate rules/regulations independent of the Department [Sections 40-2-101 and 24-1-105, C.R.S.]. PUC employees are Department employees, and the PUC's functions fall under the Department's purview similar to other Department divisions. The PUC has 115 full-time equivalent employees, including the 14 Program employees mentioned previously, who are responsible for assisting the Commissioners in carrying out their responsibilities. In accordance with the State Measurement for Accountable, Responsive, and Transparent (SMART) Government Act, the Department publishes annual Performance Plans that include strategic goals and measures for Department divisions, including the PUC. The Department also oversees or provides guidance on the PUC's budget, legislative matters, accounting, and human resources.

Program Information Systems/Databases

As shown in Exhibit 1.3, during Calendar Years 2017 through 2022, the Program used various means to document its activities. For example, the Program stored some inspection information on hard copy paper, as well as in different internal Program databases. According to Program management, the Program began using PHMSA's IA system to track some information in 2016, but did not consistently use IA until 2022.

Exhibit 1.3
Program Methods for Recording and Tracking Information on Operations and Activities, Since Calendar Year 2017

Storage Location/Database [1]	Years Used	Types of Information
Smartsheet software	2020 – Nov. 30, 2022	Inspection results, time, and notes, and some information on investigations
OnBase software (replaced Smartsheet)	Dec. 1, 2022 – Present	Inspection time, results, and notes
Federal IA system	Varied 2016 – Present	Some inspection and investigation information
Program's shared network drive (G drive)	2017 – Present	Various records such as requests for operator information, and public complaints
PUC proceedings in its Electronic Filings system	2019 – Present	Written compliance actions and some assessed penalties
Staff email	2017 – Present	Public complaints and some operator correspondence
Colorado Operations Resource Engine (CORE), the State's accounting system	2017 – Present	Collected penalties
Hard copy paper	2017 – 2021	Some inspection results and inspector qualifications
Staff individual Excel spreadsheets	2019	Inspection time and some inspection notes

Source: Office of the State Auditor's analysis of Program data and interviews with Program management and staff.
[1] According to Program management, it used software called GPSS prior to 2019 to record some inspection information but the Program no longer has the software or records of what may have been in GPSS.

Program Funding

As shown in Exhibit 1.4, the primary source of funding for the Program is federal grant funds, but the Program also receives some state funds through transfers from the PUC's Fixed Utilities Fund. PHMSA receives an annual pipeline safety appropriation from Congress, and allocates a portion of those appropriated funds to each state pipeline safety program based on PHMSA's annual evaluation of the program's performance [PHMSA Guidelines 2018 through 2022, 9]. After each calendar year is complete, Program management provides PHMSA information on Program expenses for the prior calendar year. PHMSA reimburses a percentage of expenses, generally up to 80 percent of a state program's operating expenses, based on program performance and available federal funds.

Exhibit 1.4
Program FTE, Year-End Program Expenses, and Funding from PHMSA and State Funds
Calendar Years 2019 through 2022

Fiscal Year	FTE[1]	Program Operating Expenses	PHMSA Federal Reimbursement	Percentage Reimbursed with Federal Funds	State Funds[2]
2019	6.2	$843,000	$484,200	57%	$358,800
2020	7.4	$988,900	$647,500	65%	$341,400
2021	6.9	$931,300	$597,300	64%	$334,000
2022	10.4	$1,619,900	$926,400	57%	$693,500

Source: Office of the State Auditor's analysis of information from CORE, annual Program grant applications and progress reports, And PHMSA reimbursement data.
[1] FTE reported by the Program on its grant progress reports submitted to PHMSA.
[2] State funds appropriated from the PUC's Fixed Utilities Fund.

Audit Purpose, Scope, and Methodology

We conducted this performance audit pursuant to Section 2-3-103, C.R.S., which authorizes the State Auditor to conduct audits of all departments, institutions, and agencies of the state government, and Section 2-7-204(5), C.R.S., the SMART Government Act. The audit was conducted in response to a legislative request, which expressed concerns regarding the Program's investigations and enforcement activities. Audit work was performed from July 2022 through May 2023. We appreciate the cooperation and assistance provided by Department and PUC management and staff during the audit.

We conducted this performance audit in accordance with generally accepted government auditing standards. Those standards require that we plan and perform the audit to obtain sufficient, appropriate evidence to provide a reasonable basis for our findings and conclusions based on our audit objectives. We believe that the evidence obtained provides a reasonable basis for our findings and conclusions based on our audit objectives.

The objectives of this audit were to evaluate if the Program: (1) conducts and documents gas pipeline inspections in line with applicable laws, regulations/rules, and federal grant requirements to ensure gas pipeline operators comply with intrastate gas pipeline safety requirements; (2) appropriately addresses operator noncompliance with safety regulations; and (3) effectively monitors and manages complaints received. As part of these objectives, the audit also evaluated Program processes for investigating pipeline safety-related accidents and reporting Program information to the federal grant-making agency, PHMSA, and assessed the PUC's and Department's oversight of the Program.

To accomplish our audit objectives, we performed the following audit work:

- Reviewed federal laws and regulations, PHMSA federal guidelines for state programs, state statutes and regulations, internal Program guidelines, and relevant PUC and Department policies.

- Analyzed available PUC and Program data and documentation from Calendar Years 2017 through 2022, including all aggregate data and documentation of inspections, operator noncompliance, enforcement and compliance actions, penalties, investigations, inspector training records, and public complaints, which were stored in the various locations listed in Exhibit 1.3. As part of this work, we analyzed the reliability and completeness of Program data and documentation.

- Observed a Program investigation of a pipeline safety accident involving a home explosion in Aurora, Colorado, in December 2022, and interviewed various parties on the scene, such as the homeowner and their neighbors, operator representatives, fire and rescue personnel, and Program staff.

- Analyzed PUC and Program financial data in CORE for Calendar Years 2017 through 2022.

- Reviewed data from the NRC on reported pipeline safety-related accidents, and reviewed Colorado news media stories on accidents in Colorado for Calendar Years 2017 through 2022.

- Reviewed the Program's grant applications and progress reports that it submitted to PHMSA for Calendar Years 2018 through 2022, and PHMSA correspondence of its annual performance evaluations of the Program for Calendar Years 2016 through 2021. As part of this work, we analyzed the reliability and completeness of the Program's federal reporting to PHMSA.

- Reviewed available online information for Program inspectors to determine their employment histories in the gas pipeline industry.

- Interviewed three Coloradans who reported that they submitted complaints regarding operators to the Program in Calendar Years 2018 through 2021.

- Interviewed PUC and Program management and staff, Department management representatives, and representatives from PHMSA.

As required by auditing standards, we planned our audit work to assess the effectiveness of those internal controls that were significant to our audit objectives. Details about the audit work supporting our findings and conclusions, including any deficiencies in internal control that were significant to our audit objectives, are described in the remainder of this report.

A draft of this report was reviewed by the PUC and Department. Obtaining the views of responsible officials is an important part of the OSA's commitment to ensuring that the report is accurate, complete, and objective. The OSA was solely responsible for determining whether and how to revise the report, if appropriate, based on the PUC's and Department's comments. The written responses to the recommendations and the related implementation dates were the sole responsibility of the PUC and Department. However, in accordance with auditing standards, we have included an Auditor's Addendum to responses that are inconsistent or in conflict with the findings or conclusions or do not adequately address the recommendations.

Chapter 2

Gas Pipeline Safety Program Operations & Compliance

The federal Pipeline and Hazardous Materials Safety Administration (PHMSA) administers a national pipeline safety program designed to protect the public, property, and environment from the risks posed by the pipeline transportation of natural gas and propane (collectively referred to as "gas" in this report), as well as other hazardous materials [49 CFR 171.1 and PHMSA website]. To help ensure the safety of gas pipelines (pipelines) that are within state borders—also known as intrastate pipelines—federal law allows a state to regulate safety standards and practices for pipeline facilities and transportation within its borders, only if PHMSA approves for the state to administer a gas pipeline safety program on behalf of the federal government through the Pipeline Safety Program State Base Grant (Assistance Listing No. 20.700). This approval is provided to states through an annual program certification process and federal grant application, and participating states must agree to ensure intrastate gas pipeline facilities and transportation systems comply with federal requirements [49 USC 60105 and 49 CFR 171.1]. The program certification also requires that the state adopt each applicable safety standard or, indicate that it is taking steps to adopt a standard if it was promulgated in the prior 120 days [49 USC 60105(b)(2)].

PHMSA develops minimum federal safety regulations [49 CFR 171.1] and guidelines that state programs must follow when carrying out the federal grant program to ensure that states administer gas pipeline safety programs and use federal funds in accordance with federal law [49 USC 60101, et seq.]. PHMSA's *Guidelines for States Participating in the Pipeline Safety Program* (PHMSA Guidelines) "contain guidance for how state pipeline safety programs must conduct and execute their responsibilities…. to promote consistency among the many state agencies that participate under certifications and/or agreements. The guidance contains expectations for the execution of a state agency's responsibilities, which are evaluated annually. The performance evaluation results are utilized to determine continued certification/agreement with a state agency and annual [merit-based] grant funding amounts to the state agency" [PHMSA Guidelines 2020 through 2022]. PHMSA Guidelines specify how state programs should regulate gas pipeline operators (operators), such as how states should conduct inspections and enforce safety requirements, investigate safety accidents, and report program performance to PHMSA. Federal law allows states some discretion to develop state laws, regulations, and internal state program guidelines that are stricter than federal requirements, as long as they are "substantially the same" as federal requirements [49 USC 60105(b)(7)]. As such, state programs can vary somewhat from state to state, but overall, must adhere to the federal requirements for administering the federal-state program. According to the

National Association of Pipeline Safety Representatives, which is the national nonprofit association representing state pipeline safety personnel in the United States, most states have adopted and enforce more stringent regulations than the federal pipeline safety regulations [NAPSR website].

As described in Chapter 1, Colorado's Gas Pipeline Safety Program (Program) is the federal-state program that PHMSA has approved to enforce federal requirements related to gas pipeline safety [49 USC 60101, et seq., and Section 40-2-115, C.R.S.]. The Program is administered by the Public Utilities Commission (PUC), within the Department of Regulatory Agencies (Department). As discussed in this chapter, Colorado's federal certification to administer an intrastate gas pipeline safety program is based on the Program's compliance with federal law and regulations, along with PHMSA Guidelines. The Program must also comply with Colorado statute and regulations, and internal guidelines developed by the Program. PHMSA evaluates Program performance annually, and uses information from the evaluation to help determine the amount of available merit-based federal grant funds that the Program will receive, which is the primary source of funding for Program operations. The Program's funding is supplemented with state moneys.

Our audit evaluated the Program's performance and operations, which included its practices for inspecting operators and enforcing safety standards; assessing and collecting civil penalties from operators for noncompliance with safety requirements; investigating safety accidents in Colorado; ensuring its inspectors are trained, supervised, and do not have conflicts of interest related to operators they inspect; reporting Program performance to PHMSA; managing complaints about gas pipeline safety; and managing Program operations. This chapter discusses our findings and recommendations regarding problems that we identified in each of these areas. This chapter also discusses the overall effects of the problems we identified, which collectively demonstrate that the Program has not sufficiently met federal and state requirements to help ensure gas pipeline safety in Colorado.

The remainder of this chapter includes our findings and recommendations for improving Program operations, management, and oversight to help ensure that the State regulates and monitors gas pipeline safety in a manner that protects the public.

Finding 1—Inspections of Operators

According to PHMSA, a major aspect of helping to ensure that operators comply with pipeline safety requirements involves regular inspections of pipelines and related operator facilities and processes. As such, a key responsibility of the Program is to check that operators follow safety regulations and pipeline maintenance requirements. The Program conducts these regulatory checks through either onsite or remote inspections of the operators' safety plans and policies, qualifications, and equipment. As described in Chapter 1, operators are (1) **public operators**, such as Xcel Energy or Colorado Springs Utilities, that serve more than 100 customers using multiple regulated gas sources, and (2) **private operators**, including master meter gas system operators, such as apartment complexes, that serve fewer than 100 customers from a single gas source.

Program management develops a scheduling plan for the inspections that it needs to conduct in the upcoming 5 or 6 years because each operator must be inspected at least every 5 years, per the federal requirements described below. Inspections review different units of an operator's facilities, such as different types of equipment and gas pipelines (e.g., an inspection of transmission or distribution pipelines), within each region in the state where the operator provides service. The Program also conducts various types of inspections of each operator unit, as discussed further below. The Program's scheduling plan is updated annually and tracks information on the operators that should be inspected, each operator unit or aspect of the operator's gas pipeline system or equipment that should be inspected, and the year that the Program last inspected the operator unit.

The Program uses PHMSA's federal inspection system, called Inspection Assistant (IA), to create an annual list of inspections that need to be scheduled for the upcoming year. The Program also uses IA to conduct each inspection using a standard set of questions developed by PHMSA, which cover the items that need to be reviewed to help determine operator compliance with regulations. The Program also uses IA to track certain inspection information including the range of dates when a particular operator was inspected during the year, the operator units inspected, and some inspection results such as whether the inspection found that the operator was in compliance or noncompliance with federal regulations. Additionally, the Program uses internal state databases to track the details of inspections. Specifically, from Calendar Years 2020 through November 30, 2022, the Program used Smartsheet software to track details, such as the date(s) of each inspection, hours spent on each inspection, inspector notes, and possible violations or noncompliance found for each unit inspected. In December 2022, the Program replaced Smartsheet with software called OnBase to track inspection information.

Some examples of noncompliance that an inspection may identify include:

- Inadequate records management, such as operator failure to retain records of operator qualifications.

- Technical operator error, such as not performing required repair of a known gas leak, or unqualified workers performing maintenance or construction.

- Inadequate operator safety procedures or plans, such as lack of a plan to address an emergency.

When an inspection identifies operator noncompliance, the Program may issue a compliance action, such as a warning or a penalty assessment, to an operator in order to help remediate the noncompliance and prevent recurrence. Compliance actions are discussed further in our *Enforcement of Safety Regulations* Finding. According to the Program's available inspection data and documentation, in Calendar Year 2022, the Program conducted inspections of 102 out of the total of 115 operator units that Program management told us that it was aware of—4,425 inspections of different types of the 43 public operators, and 52 inspections of different types of 18 of the 22 private master meter operators. Most of these inspections were remote inspections of operator records and safety-related plans; some inspections were onsite, such as of equipment and construction.

What was the purpose of the audit work and what work was performed?

The purpose of the audit work was to assess whether the Program has conducted operator inspections and documented inspection results in accordance with federal and state requirements. We reviewed the Program's 5-year scheduling plan for Calendar Years 2018 through 2022, 6-year scheduling plan for Calendar Years 2021 through 2026, and annual lists of planned inspections that needed to be scheduled for Calendars Years 2020 through 2022. For Calendar Years 2020 through 2022, we reviewed the records that the Program recorded in the federal IA system and the Program's state internal data to identify the planned inspections that needed to be scheduled and the inspections that were completed, and compared this information to the scheduling plans covering the various required types of inspections for these years. We used Program data to assess whether the Program conducted inspections in accordance with federal and Department performance measures. We reviewed PHMSA's performance evaluations of the Program for Calendar Years 2016 through 2021, along with the findings and the Program's responses to them. We also interviewed Program management and inspectors to understand how inspections were planned, scheduled, conducted, and documented.

How were the results of the audit work measured?

A state program's pipeline safety efforts depend on information obtained through inspections and evaluation of operator compliance [PHMSA Guidelines 2018 through 2022, 5.1]. According to PHMSA, an operator should have sufficient communication and controls to ensure uniform design, construction, operation, and maintenance procedures for gas pipeline facilities; therefore, inspections should cover an operator's entire system [PHMSA Guidelines 2018 through 2022, Glossary]. Federal regulations and guidelines, and state statute and regulations, establish requirements for planning, scheduling, and conducting Program inspections, as follows:

- **The Program should conduct inspections within required timeframe intervals.** The Program must inspect operator units within the minimum timeframe intervals established by PHMSA, and must inspect all operator units at least once every 5 years [PHMSA Guidelines 2018 through 2022, 5.1]. In addition, for certain types of inspections, Colorado statute [Section 40-2-115, C.R.S.] and PHMSA Guidelines [2018 through 2022, 5.1] allow the Program to have more frequent inspections than federal regulations require. For example, PHMSA Guidelines state that standard inspections must be completed within a minimum of 5 years, unless the state program develops shorter timeframes, in which case, a comprehensive review of all components should be completed within a time period specified by the state. As such, the Program has developed internal guidelines with shorter intervals for some types of inspections.

Exhibit 2.1 lists the minimum inspection intervals required by PHMSA for each type of inspection, and the intervals established by the Program for Colorado. The required timeframe intervals for inspections are intended to help ensure that each operator's entire system is inspected regularly. The purpose of the Program's inspection schedule plans, which list operator units to be inspected during the coming year, is to help the Program conduct inspection types for each operator unit within the required intervals for the upcoming year.

Exhibit 2.1
Minimum Inspection Timeframe Intervals, per Federal PHMSA and Colorado Program Guidelines, by Inspection Type

Inspection Type & Definition	Federal Minimum Inspection Intervals[1, 3]	Colorado Minimum Inspection Intervals[2]
Standard [3] — Checks operator "general code compliance, including a comprehensive and thorough review of an operator's compliance records, operations and maintenance plans, emergency procedures, public awareness plans, control room management, drug and alcohol programs and pipeline facilities. Includes, at a minimum, an evaluation of such items as corrosion control, leakage surveys, overpressure protection and pressure regulating equipment, odorization levels and equipment, repaired and/or active leaks, emergency valves, emergency response."		
Field Inspection (per operator unit)	5 Years, unless state program has established shorter timeframe[3]	2 Years
Master Meter Operator Comprehensive Inspection		4 Years
Records of Operation and Maintenance (per operator unit)		2 Years
Plan for Operation and Maintenance		5 Years
Plan for Control Room Management		5 Years
Plan for Public Awareness		5 Years
Plan for Drug and Alcohol Testing		5 Years
Emergency Plan Procedures		3 Years
Field Observation of Emergency Response		1 Year
Integrity Management — Checks operator procedures to mitigate pipeline deterioration and leaks.		
Plan for Distribution Integrity Management Program	5 Years	5 Years
Implementation of Distribution Integrity Management Program	1 Year	1 Year
Plan for Transmission Integrity Management Program	5 Years	5 Years
Implementation of Transmission Integrity Management Program	1 Year	1 Year
Damage Prevention — Checks operator plans and preventive measures for mitigating the effects of a pipeline failure, such as in the event of a pipeline strike.		
Damage Prevention Program	5 Years	2 Years
Damage Prevention Data	5 Years	1 Year
Operator Qualifications/Training — Checks if an operator and its contractors have sufficient experience and ability to perform their duties.		
Plan for Operator Qualifications	5 Years	5 Years
Compliance Follow-up — Checks if the operator has corrected past noncompliance.		
Follow-up Compliance Inspections	As needed	
Inspections and investigations of accidents/incidents — Determines the cause and/or responsible party for any accidents/incidents.		
Inspections and investigations of accidents/incidents	As needed	

Source: Office of the State Auditor's review of PHMSA Guidelines and Colorado Program internal guidelines.
[1] Federal inspection intervals in place since at least 2018.
[2] State inspection intervals established in internal guidelines developed by Colorado's Pipeline Safety Program, last updated September 2021 and July 2022.
[3] PHMSA Guidelines state that the standard inspections must be completed at least every 5 years, unless the state develops shorter timeframes, in which case, all components of the standard inspection should be completed within the time period specified by the state [PHMSA Guidelines 2018 through 2022, 5.1].

- **The Program should meet federal requirements and state performance measures for completing a minimum number of inspection days each year.** According to PHMSA Guidelines, "to meet the State Agency's commitment to pipeline safety, each State Agency must maintain an adequate, base-level number of pipeline safety inspection activity days," and "each full-time equivalent (FTE) pipeline safety inspector…must devote a minimum of 85 Inspection Person-Days…to pipeline safety compliance activities each calendar year" [PHMSA Guidelines 2018 through 2022, 4.1 and 4.2]. PHMSA defines an Inspection Person-Day as all or part of a day spent by an inspector when inspecting an operator to determine compliance [PHMSA Guidelines, Glossary].

  In addition, the Department's annual Performance Plans for Fiscal Years 2021 through 2023 included one strategic measure for the Program, which was to conduct 185 inspection days per quarter for the "protection of consumers through effective enforcement." The State Measurement for Accountable, Responsive, and Transparent (SMART) Government Act, requires departments to develop these annual strategic plans with performance measures to guide department major functions and evaluate performance over time [Section 2-7-204(3), C.R.S.].

- **Inspections should be scheduled and conducted based on risk.** According to PHMSA Guidelines and state regulations [PHMSA Guidelines 2018 through 2022, 6, and 4 CCR 723-11013], inspections may need to be conducted based on safety accidents/incidents, public complaints, or other indications of safety risk; these are inspections that are in addition to those conducted to meet timeframe intervals. PHMSA Guidelines also specify that inspections must be based, in part, on statewide risk models that consider public exposure risks and operation risks [PHMSA Guidelines 2018 through 2022, 5.1]. As such, PHMSA instructs state programs to evaluate risk based on factors such as pipeline materials, population density of the surrounding areas, operator compliance issues, and operator safety culture [PHMSA Guidelines 2018 through 2022, 4.1]; create an annual risk-based list of inspections for the coming year; and incorporate the list into a written plan [PHMSA Guidelines 2018 through 2022, 5.1]. The Guidelines also instruct state programs to create a risk ranking of each operator based on the specific risks that their pipelines may pose. For example, operators would be assigned a higher risk ranking if the operator has pipelines that are prone to leaks or corrosion.

- **Inspections should be documented consistently in state records, and quality records should be maintained.** Federal regulations mandate that state programs maintain adequate state records, as PHMSA determines [49 CFR 198.11]. The Program should retain and record complete and accurate information needed to regulate interstate pipeline facilities [PHMSA Guidelines 2018 through 2022, 5.1], and to meet the Program's mission of confirming compliance with and enforcing the State's intrastate gas pipeline safety regulations in order to provide public safety to the citizens of Colorado [Section 24-17-102(1), C.R.S.; 4 CCR 723-11000; and Program website]. PHMSA Guidelines state, "Recordkeeping is vital to the operation of a pipeline safety program. State files shall be well organized and accessible (this includes electronic files)," and, as of 2021, PHMSA requires that Program records be kept for a minimum of 5 years plus the current year [PHMSA Guidelines 2021 and 2022, 8.3]. From 2018 through 2020, the requirement was to maintain records a minimum of 3 years plus the current year. The state "must keep records of all pipeline safety inspections and follow-up activities. Inspection records should include the inspection dates, the name of the inspector, the location and type of facilities inspected, [the operator and inspection unit], the names and titles of operator staff contacted at the inspection unit, the regulation sections checked for compliance, and the resulting evaluation conclusions" [PHMSA Guidelines 2018 through 2022, 5.1.7].

What problems did the audit work identify and why do these problems matter?

Overall, we found that the Program has not consistently complied with federal and state requirements for conducting operator inspections and documenting the results, as described below.

- **The Program has incomplete or missing inspection records.** We found that the Program does not have any state internal inspection data or documentation for Calendar Years 2017 and 2018, as required, and has incomplete records for Calendar Year 2019. Specifically, the Calendar Year 2019 records do not consistently track key information such as the operator or unit inspected, inspection date, or inspection type. Additionally, Program management and staff stated that they did not record inspections in IA consistently during Calendar Years 2017 through 2021, and did not use IA for recording all inspections until Calendar Year 2022. For example, the Program did not record any inspections of master meter operators in IA during Calendar Years 2017 through 2021; it only has paper records of some of these inspections. In 2017, PHMSA conducted its annual performance evaluation of the Program for Calendar Year 2016, which stated that the Program had purged its inspection records and they were not available for PHMSA review so it was unclear if all types of inspections were conducted, as required. In 2020 and 2021, PHMSA also had recordkeeping findings because the Program was not answering all inspection checklist questions in IA or using other appropriate forms to document inspections and the results. In January and September 2022, the Program provided PHMSA written responses to these federal findings and stated that it agreed to address them.

  Additionally, the Program did not consistently document the specific location coordinates or addresses of the inspections in available notes fields in IA during Calendar Years 2017 through 2022, or in available internal state data for Calendar Years 2019 through 2022. For example, the Program's state data on inspections conducted during Calendar Years 2019 through 2022 related to inspectors' observation of operator field assets and materials (e.g., pipelines, meters), and operator personnel, but did not include sufficient location information on the specific unit item inspected for 1,030 of 3,406 inspections (30 percent). Therefore, we were unable to determine what had been inspected and where; for many records the location was blank or only a city was listed as the location. When the Program does not document the precise locations of its inspections then it cannot ensure that it inspects all aspects of operator units (e.g., pipelines, meters) in different locations, and may not be able to follow up to ensure that any identified safety issues or instances of noncompliance have been corrected. Further, when the Program does not have evidence that it inspected operators or is unable to ensure that all units are inspected, there is an increased risk to public safety.

- **The Program did not inspect operators within required timeframe intervals.** Due to the lack of Program records for inspections for Calendar Years 2017 through 2019, we were unable to assess whether the Program conducted inspections in compliance with requirements for inspection types that have 4-year or 5-year intervals. We reviewed inspection records to identify the most recent Program inspections of each type, for each operator and unit, through December 31, 2022, to assess whether the Program met required 1-year to 3-year intervals. Program records showed that for Calendar Years 2020 through 2022, the Program did not meet interval requirements for the types of inspections that have 1-year to 3-year intervals, as required. Exhibit 2.2 summarizes this analysis.

Exhibit 2.2
Types of Program Inspections Not Completed within Required Timeframe Intervals
Calendar Years 2020 through 2022

Inspection Type & Definition	Federal Minimum Inspection Intervals	Colorado Minimum Inspection Intervals [1]	Did Inspections Meet Federal Interval Requirements?	Did Inspections Meet State Interval Requirements?	Inspections Not Meeting Interval Requirements, as of December 31, 2022
Field Inspection (per operator unit)	5 Years	2 Years	No	No	89 of 115 units (77%) not inspected within 2 years
Master Meter Operator Comprehensive Inspection	5 Years	4 Years	Insufficient Data	Insufficient Data	
Records of Operation and Maintenance (per operator unit)	5 Years	2 Years	Insufficient Data [2]	Insufficient Data [2]	
Plan for Operation and Maintenance	5 Years	5 Years	Insufficient Data [2]	Insufficient Data [2]	
Plan for Control Room Management	5 Years	5 Years	Insufficient Data	Insufficient Data	
Plan for Public Awareness	5 Years	5 Years	Insufficient Data	Insufficient Data	
Plan for Drug and Alcohol Testing	5 Years	5 Years	Insufficient Data	Insufficient Data	
Emergency Plan Procedures	5 Years	3 Years	No	No	59 of 59 operators (100%) not inspected within 3 years [4]
Field Observation of Emergency Response	5 Years	1 Year	No	No	52 of 59 operators (88%) not inspected within 1 year
Plan for Distribution Integrity Management Program	5 Years	5 Years	Insufficient Data	Insufficient Data	
Implementation of Distribution Integrity Management Program	1 Year	1 Year	No	No	51 of 59 operators (86%) not inspected within 1 year
Plan for Transmission Integrity Management Program	5 Years	5 Years	Insufficient Data	Insufficient Data	
Implementation of Transmission Integrity Management Program	1 Year	1 Year	No	No	52 of 59 operators (88%) not inspected within 1 year
Damage Prevention Program	5 Years	2 Years	Insufficient Data	Insufficient Data [3]	
Damage Prevention Data	5 Years	1 Year	Insufficient Data	Insufficient Data [3]	
Plan for Operator Qualifications/Training	5 Years	5 Years	Insufficient Data	Insufficient Data	
Follow up Compliance Inspections	As needed		NA	NA	
Inspections and Investigations of Safety Accidents/Incidents	As needed		NA	NA	

Source: Office of the State Auditor's analysis of Program inspection data and documentation.
[1] The Program has established shorter timeframe intervals than the federal 5-year minimum; therefore, the Program should meet the Program-established shorter timeframes.
[2] As described below, Program records indicated that in Calendar Year 2022, one inspector conducted all operations and maintenance inspections of all operators in 1 half-day; however, operator names and units were not documented, so it is unclear if all operators and units were truly inspected.
[3] As described below, Program records indicated that in Calendar Year 2022, one inspector conducted all damage prevention inspections of all operators in 1 day; however, operator names were not documented, so it is unclear if all operators were truly inspected.
[4] Program records did not show inspections of operator emergency plans in Calendar Years 2020 through 2022.

PHMSA's annual evaluations of the Program for Calendar Years 2020 and 2021 also found that the Program did not conduct inspections in line with required intervals. Specifically, PHMSA's findings stated that the Program was not performing and completing all inspections within the maximum 5-year time interval. Additionally, while we found that the Program did not meet the State's required 1-year interval to conduct integrity management inspections of all units, PHMSA also found that, in 2020 and 2021, the Program did not have documentation to show that these integrity management inspections had even been completed within the federal 5-year requirement.

When inspections are not conducted within required intervals, the State cannot ensure that each operator's entire system complies with pipeline safety requirements to mitigate the risk of potential safety problems. Irregular inspections can lead to safety concerns not being found or addressed in a timely manner, which can increase the risk that these concerns will cause an accident and/or endanger the public.

- **Some inspections were not conducted in a manner that is thorough and/or helps ensure public safety.** Our review of Program data and documentation found:

  - **The Program has not conducted inspections of all private master meter operators.** According to Program records, the Program had inspected a total of 18 master meter operators in the state as of December 2022; however, the Program did not maintain documentation of the inspections of these operators until Calendar Year 2021 and has not identified all master meter operators that may need an inspection. Program management and staff told us that inspections of master meter operators were conducted on paper, rather than using federal or state databases, and the inspection results were not retained prior to 2021 unless the inspection identified a violation. When the Program is unable to identify all master meter operators, it cannot ensure that they have all been inspected and that they are compliant with safety requirements, which can create a risk to public safety. Master meter operators serve communities, such as apartment complexes and mobile home parks; if the Program is not sufficiently inspecting all of these operators to ensure their compliance with safety requirements, there is greater risk that a pipeline safety accident involving one of these operators could affect many people in their communities.

  - **The Program recorded conducting certain types of inspections for all operators in 1 day or less.** In Calendar Year 2022, Program records indicated that one inspector completed all operations and maintenance inspections for all operators within 1 half-day, and that another inspector completed all damage prevention inspections for all operators within 1 day. The inspectors documented all of the inspections in one record, rather than creating a record for each inspection, and did not document the operator names or units. Therefore, it is unclear if all operators or units were truly inspected. These two inspectors documented that they did not identify violations for any of the operators or units. Specifically, we found:

    - Program data had one record indicating that one inspector conducted all operations and maintenance inspections of all operators' units remotely within 1 half-day (e.g., 4 hours) in October 2022. Although the data does not indicate how many units were inspected, if the inspector had reviewed all 115 units that Program management was aware of at that time, on average, the inspector could have only taken 2.1 minutes to complete each inspection if they did not take any breaks during the 4-hour period. One inspector completing all operations and maintenance inspections for the year within a half-day does not appear feasible because these inspections should include reviewing operator records, processes, and procedures for gas pipeline operations and maintenance, and are intended to allow inspectors to detect signs of larger systematic issues with the operator [Colorado Program internal guidelines].

- Program data had one record indicating that another inspector conducted all damage prevention inspections of all operators in the state remotely, within one 8-hour day in April 2022. Although the data does not indicate how many units were inspected, if the inspector had reviewed all 61 operators that Program management was aware of at that time, on average, the inspector could have only taken 7.9 minutes to complete each inspection if they did not take any breaks during the 8-hour period. One inspector completing all damage prevention inspections for the year within 1 day does not appear feasible because these inspections should include reviewing operator plans and preventive measures for mitigating the effects of pipeline failure, including whether the operator has prudent excavation processes and procedures and qualified excavators [Colorado Program internal guidelines]. Additionally, the inspector who conducted these inspections had not completed required federal training on damage prevention; lack of inspector training is discussed further in our *Inspector Training and Supervision* Finding.

When many inspections are conducted by one person in a short time, there is a risk that the inspections are not thorough or complete to verify that the operators have sufficient safety measures. For example, damage prevention inspections are intended to help ensure that the operator has measures in place to prevent or mitigate a pipeline rupture from outside forces, such as when a pipeline is struck (e.g., during construction, a tree fall, landscaping). According to the federal National Response Center (NRC), which receives operator reports of gas pipeline safety accidents, 95 out of 303 (31 percent) safety accidents that operators reported in Colorado from 2017 through 2022 were due to pipeline strikes. These 95 accidents resulted in two deaths, two injuries, and more than $2 million in property damage.

- **The Program conducts remote inspections for inspection types that would appear to be needed to be conducted onsite.** For example, in Calendar Years 2021 and 2022, the Program conducted remote inspections for 122 inspections that required observation of operator field assets and materials (e.g., pipelines, meters), and/or operator personnel type; these types of inspections are intended to include onsite observation. PHMSA allows state inspectors to conduct remote inspections when appropriate for the type of inspection being conducted, but inspections must continue to be thorough, complete, and ensure operator compliance. In Calendar Years 2021 and 2022, about 55 percent of all documented Program inspections were conducted remotely. Some Program staff we interviewed said they were concerned with the Program conducting many inspections remotely because violations could be missed when there is not a review of operations onsite at the operator's location. Staff also said onsite inspections of records may catch issues that cannot be identified through remote inspections of operators' self-reported records, and some staff were concerned that an operator could alter records before sending them to the Program, or only send certain records for remote inspection, which staff felt increased the risk of the Program missing a safety issue during an inspection.

- **The Program has not consistently met the federal inspection-day requirement or the Department performance measure.** For Calendar Years 2019 through 2022, we calculated the number of inspection days for the Program by dividing the total number of inspection hours that the Program recorded in each year, by 8 hours. We then multiplied the number of calculated days by the actual inspector FTE during the year, accounting for part-time and full-time inspectors as well as the inspectors hired during the year. As shown in Exhibit 2.3, in 2 of the 4 years reviewed, the Program did not meet the federal requirement for 85 inspection days per year, per FTE inspector, which is the requirement that all states must meet to help ensure inspectors are spending sufficient time conducting inspections. Working a 40-hour work week, full-time employees work up to 260 8-hour days per year, so the 85 inspection-day per year requirement for state programs means that each full-time inspector should be conducting inspections about 33 percent of all possible work days per year, on average.

Exhibit 2.3
Program Inspections Not Meeting Federal Minimum Inspection-Day Requirements
Calendar Years 2019 through 2022

Year	Inspector FTE	Federal Minimum Days Required for FTE	Actual Inspection Days Completed by Program FTE	Difference in Requirement and Actual	Percentage of Federal Inspection Day Requirement that Program Met
2019	5.83	495.5	445.6	(49.9)	90%
2020	6.5	552.5	609.0	56.5	110%
2021	6.0	510.0	320.8	(189.2)	63%
2022	9.5	807.5	861.8	54.3	107%

Source: Office of the State Auditor's analysis of the Program's federal grant progress reports and state internal data for Calendar Years 2019 through 2022.

In addition, in Fiscal Years 2021 and 2022 the Program did not meet the Department's strategic performance measure of 185 inspection days per quarter for 6 of the 8 quarters. Specifically, in the 6 quarters that did not meet this 185-day measure, the Program completed between 54 and 151 inspection days per quarter. For the 2-year period, on average, the Program completed 136 inspections days per quarter across all 8 quarters. Additionally, while this quarterly performance measure appeared to be reasonable for the Program to meet in Calendar Year 2022, given the number of inspectors that the Program employed, it is not clear that this measure was reasonable for Calendar Years 2019 through 2021 when the Program employed fewer inspectors.

When the Program does not meet federal inspection-day requirements or Department performance measures for inspection days, the Program is not meeting minimum standards established to help ensure that safety requirements are enforced and that pipelines are adequately safe for the public.

- **Some operators were not inspected when the Program identified risks.** The Program has not inspected operators based on safety accidents/incidents, public complaints, or other indications of safety risk related to the operators, as required. We found:

    - The Program did not retain records of pipeline safety accidents/incidents prior to May 2021, so it is unclear whether the Program inspected the three public operators that were involved in 14 different accidents between January 2020 and April 2021, more frequently than the operators that did not have safety accidents.

    - The Program did not conduct inspections of public operators as a result of public complaints in Calendar Years 2020 through 2022. Specifically, the Program did not track complaints that it received, so complaints could not be considered as a risk factor when planning and scheduling inspections. See our *Complaint Management* Finding for additional information on this problem.

    - According to Program management and staff, the Program does not inspect operators with more or repeat noncompliance more frequently than operators with greater compliance. For example, since May 2017, one public operator serving Aurora, Colorado, has been involved in five pipeline safety accidents in this area. Although Program inspection records indicate that inspectors have identified 46 instances of noncompliance for this operator, the records do not show that there have been follow-up compliance inspections of this operator for this location.

  Lack of sufficient, risk-based scheduling of inspections may allow an operator's noncompliance or safety issues to continue without being identified or followed up on, which could negatively affect public safety. Had the Program conducted risk-based inspections of the operators with accidents, the Program may have helped to identify unsafe conditions and address noncompliance, which could have potentially helped mitigate or prevent additional accidents.

Why did these problems occur?

The problems that we identified related to conducting and documenting inspections occurred for the following reasons:

- **The Program lacks consistent data/document retention practices and tools.** The Program has not implemented record retention practices to address PHMSA findings in this area from

2016, 2020, and 2021. Program management said that it has not had sufficient time to address PHMSA's findings in this area. According to Program management, the Program retained no internal documentation of inspections conducted during 2017 and 2018 due to various reasons, including: (1) not having the former Program Chief/Manager's inspection data and documentation after they retired because the information was either not documented in Program systems or was not provided to Program staff upon the Chief/Manager's retirement; (2) data from 2017 through 2019 being lost due to software changes in 2020; and (3) data being deleted due to Program management's and staff's lack of familiarity with PHMSA's retention requirements. Additionally, Program management indicated that staff and management may have misrecorded inspection information in the records that were provided to the audit team. Overall, the Program has not developed processes for consistent and accurate data entry of inspections. For example, in 2019, Program inspectors used their own Excel spreadsheets to track their inspection hours, but they did not track this information consistently. The Program has also not developed a method to track all inspection information in a centralized database or system. During Calendar Years 2017 through 2022, various information on inspections was stored on paper, in federal grant progress reports, in three different internal Program databases, in staff's individual Excel spreadsheets, in the federal IA system, and on the Program's shared network drive. Lastly, Program management and staff told us that the Program began using the federal IA system to track some inspection records in 2016, but did not consistently use IA to record all inspections until 2022.

- **Program staffing needs not reassessed based on current federal and state inspection requirements.** According to the PUC, a lack of Program inspectors in Calendar Years 2017 through 2022 has limited the number of inspections that the Program could complete. In Calendar Years 2020 and 2021, the Program had between 6 and 6.5 FTE inspectors to conduct all required inspections for the at least 61 operators throughout Colorado. According to the PUC, a staffing shortage and personnel changes caused the Program to not meet federal minimum inspection days during this time. As a result, the PUC requested additional funding for more inspectors, which was approved through Senate Bill 21-108. This legislation recognized that the Program could not keep up with vital safety inspections and enforcement, and allocated funding to the PUC to add 3.7 FTE inspectors for the Program. In 2022, the Program hired five additional inspectors, for a total of 12 full-time and part-time inspectors. However, the Department, PUC, and Program management have not conducted a comprehensive assessment of Program staffing needs to determine how many inspectors are currently needed to meet all relevant federal and state requirements for inspections.

- **Lack of sufficient processes and guidance to ensure inspections are conducted accordance with scheduling plans and required intervals, federal requirements, and the Department performance measure.** First, although the Program maintains a plan to schedule inspections based on required intervals, the Program has not implemented a sufficient process to ensure that inspections are conducted during the year, as planned, to meet the intervals. For example, the Program does not appear to regularly compare the scheduling plan to the inspections that have been scheduled, and ensure that staff are scheduling inspections with operators during the calendar year, as appropriate, to carry out the plan. Exhibit 2.4 shows the difference between the number of each operator inspection units that the Program scheduled for various inspection types compared to the operator inspection units that had *any* inspection.

Exhibit 2.4
Program Inspections Planned verses Completed[1]
Calendar Years 2020 through 2022

	2020	2021	2022
Number of Operator Units Planned for Inspection to Meet Interval Requirements	45	39	65
Number of Completed[1] Inspections of Operator Units	40	32	51[1]
Percentage of Planned Inspections Completed	89%	82%	78%[1]

Source: Office of the State Auditor's analysis of the Program's scheduling plans, inspection records in IA, and Program internal data for Calendar Years 2020 through 2022.
[1] The number of inspections that were completed as of December 31, 2022.

Second, Program management and inspectors have employed some shortcuts to help complete federally-required inspections that may have compromised the quality of these inspections. For example, according to Program management, it transitioned to more remote inspections due to the COVID-19 pandemic, and it has conducted some inspections in short timeframes without adequately documenting the inspections, due to a lack of inspection staff in recent years. Based on our audit work and discussions with Program management and staff, it appears that some shortcuts have also been employed for the inspections conducted by some Program staff due to a lack of staff knowledge, experience, and training on federal and state requirements. For example, several inspectors were hired from the gas pipeline industry in 2022, and have been conducting inspections before completing many required federal trainings on pipeline safety and inspections. Problems we identified related to staff training are discussed further in our *Inspector Training and Supervision* Finding.

Additionally, during this audit, some Program staff raised concerns that management's lack of understanding of federal requirements has led to insufficient processes to plan and conduct inspections. The Program's current manager was hired from another executive branch department in April 2021, and has been working to learn federal and state pipeline safety regulations and requirements, and complete required federal training. However, PHMSA's annual evaluation of the Program for Calendar Year 2021 (completed in 2022) had a finding that the Program Manager did not have "sufficient knowledge of pipeline safety technology, enforcement applications, and administrative procedures." The Program agreed, and responded that the Manager had been with the Program about 1 year and that the finding would be remedied with time.

Third, PUC and Program management told us they had not been aware of the 185 inspection day per quarter strategic measure that has been in the Department's performance plans for the past 3 years. Therefore, the PUC and Program have not had a process to assess the measure to determine if it is reasonable or if the Program is meeting the measure, or to report Program performance with the measure to the Department. PUC and Program management were unsure who developed this performance measure for the Program, but presumed it may have been the former PUC Director who retired in 2022, or the former Program Chief/Manager who retired in 2021.

- **The Program has not developed a process to identify all private master meter operators that must be inspected.** Program management stated that it does not identify master meter operators or have a process to track them unless they self-report their existence to the Program or are involved in a safety accident. Program management stated that it does not believe it is the Program's responsibility to identify all master meter operators, although PHMSA and state regulations require inspections of all of these operators. According to Program management, it is the responsibility of master meter operators to notify the Program that they are operating in the state. As a result, the Program has not developed a process to determine which master meter operators have not notified the Program of their existence so that the Program can identify the noncompliance and enforce notification. For example, Program staff indicated that the Program could contact the public operators—who supply private master meter operators with gas, which the master meter operators then provide to their customers—to collect more information on the master meter operators in Colorado.

- **The Program has not developed procedures to assess risk, and inspect based on risk.** Program management and inspectors told us that the Program's three lead inspectors schedule the upcoming year's inspections based on their industry expertise and knowledge, and that once inspections are scheduled, it is uncommon for the Program to deviate from the schedule based on risks that arise. Although Program management provided a draft of a risk-based process during our audit, this draft did not include processes for the Program to:

  - Assess the extent to which operators may meet required risk factors (e.g., pipeline materials, population density of the area, operator compliance, and operator safety culture);

  - Assess risk based on operator accidents/incidents and noncompliance, or public complaints;

  - Create a risk ranking of each operator based on the specific risks that they may pose, as required; and

  - Create an annual risk-based list of inspections for the coming year and incorporate the list into the scheduling plan, as required.

During the audit, Program management recognized the need to assess risk, and conduct inspections based on the risk assessment, and said that it intends to implement a risk-based process. In order to implement a process to review and consider risks when planning and scheduling inspections, the Program will need to first implement processes to consistently track:

- Operator violations identified during inspections and compliance actions, as discussed in our *Enforcement of Safety Regulations* Finding;
- Safety accidents/incidents, as discussed in our *Investigations of Safety Accidents* Finding; and
- Public complaints, as discussed in our *Complaint Management* Finding.

Recommendation 1

The management and staff of the Public Utilities Commission should work with the Department of Regulatory Agencies (Department) to ensure that the Gas Pipeline Safety Program (Program) improves its inspection processes and practices, in accordance with federal and state requirements, by:

A. Implementing Program practices and tools to document complete information on inspections, and retain the inspection data/documents, in compliance with federal requirements.

B. Assessing Program staffing, and request an appropriation for more staff, as needed, based on the assessment, to ensure there are a sufficient number of inspectors to meet the Program's federal and state responsibilities to regulate gas pipeline safety, including to meet all inspection requirements. This may include working with the Department to revise the Department's strategic measure for Program inspection days, to help ensure the measure is reasonable based on the number of inspectors employed by the Program.

C. Developing and implementing Program processes and guidance to help ensure that inspections of all operators are conducted in a thorough and complete manner that ensures public safety. This should include processes to conduct inspections in line with scheduling plans, required timeframe intervals, federal inspection-day requirements, and any Department performance measures.

D. Developing and implementing a Program process to identify private master meter operators within the state that must be inspected.

E. Developing and implementing written Program procedures to assess risk, at least annually, based on required factors, and incorporating the risk assessment into the scheduling plan to help ensure that operators that are assessed as high risk are inspected more frequently.

Response

Public Utilities Commission and Department of Regulatory Agencies

A. Agree
   Implementation Date: March 2024

   The PUC will work with the Department of Regulatory Agencies (the Department) to document complete inspection information, as outlined in federal and state guidelines, and retain Program records in compliance with federal and state requirements.

B. Agree
   Implementation Date: March 2024

   The PUC will work with the Department to assess Program staffing, and request an appropriation for more staff as appropriate to ensure there are a sufficient number of inspectors to meet the Program's federal and state responsibilities to regulate gas pipeline safety, including meeting all applicable inspection requirements.

C. Agree
   Implementation Date: March 2024

   The PUC will update the State Agency's written Program Guidelines to improve the Program's written procedures and will implement Program processes to ensure inspections are conducted in a thorough and complete manner in line with scheduling plans, guidance for inspection intervals, guidance for inspection response, federal inspection-day requirements, and any Department performance measures, as appropriate.

D. Agree
   Implementation Date: March 2024

   The PUC will update the State Agency's written Program Guidelines to develop and implement a process to identify master meter operators within the state that must be inspected. The PUC will incorporate the newly registered operators into the inspection planning process.

E. Agree
   Implementation Date: March 2024

   The PUC will update the State Agency's Program Guidelines to implement written procedures to assess risk in accordance with the requirements as outlined in applicable inspection requirements. This annual assessment will inform the scheduling plan for the following year.

Finding 2—Enforcement of Safety Regulations

According to PHMSA, operator compliance with safety regulations is critical to preventing safety accidents, and compliance involves imposition of an appropriate administrative, civil, or criminal remedy in the event that an inspection identifies a violation of regulations. States that have gas pipeline safety programs are responsible for enforcement, while the federal government is primarily responsible for issuing safety regulations [PHMSA website].

Colorado's Program was created to confirm compliance with and enforce the State's intrastate gas pipeline safety regulations in order to provide public safety to the citizens of Colorado [Section 40-2-115, C.R.S.]. When operators fail to comply with safety regulations, they are considered to be in noncompliance, which is "a violation or probable violation of any section or any subsection of federal or state pipeline safety regulations" [PHMSA Guidelines 2018 through 2022, Glossary]. All instances of noncompliance are considered probable until completion of the appropriate enforcement actions [4 CCR 723-11500(c)].

If an inspector determines that an operator has complied with pipeline safety requirements, the inspector documents that the inspection results are "satisfactory." According to the Program, if an inspector determines that an operator has not satisfactorily complied with all pipeline safety requirements, the Program classifies the noncompliance as either a "concern" or as "unsatisfactory." Operator noncompliance and the inspector's classification of the noncompliance varies, but according to the Program's internal guidelines, the Program utilizes "concern" when there is minor noncompliance, such as errors in an operator's records, and Program management stated that "concern" is also used to classify noncompliance when the identified problem is "open to interpretation." Program internal guidelines state that the Program utilizes "unsatisfactory" when the operator's noncompliance is "not meeting requirements."

The Program may issue a compliance action to an operator if an inspection identifies noncompliance in order to help remediate the noncompliance and prevent recurrence. One compliance action can cover multiple instances of noncompliance and take the form of a letter that explains the operator's noncompliance, and may include an order directing compliance or some type of alternative action. The types of compliance actions typically used by the Program to notify operators of noncompliance are: (1) warnings, and (2) notices of probable violations that direct operator compliance or corrective action. According to Program staff, when an inspector identifies noncompliance that is classified as a concern or unsatisfactory, the inspector sends a recommendation for a compliance action to the Program Manager, who determines whether or not a compliance action will be issued to the operator and, if so, the type of action.

According to Program management, if the Program issues a notice of probable violations to an operator, then the notice includes a statement of the inspection results, the regulations violated, an assessed penalty amount that is recommended by the Program or an alternative action that the operator should take in lieu of paying a penalty. For a notice of probable violations, there is a proceeding or proceeding hearing with the Commissioners (or an Administrative Law Judge if the PUC assigns a judge) to allow the operator an opportunity to contest the notice and any penalty assessment, or to request an alternative agreement. For proceedings, an operator may provide the Commissioners a written explanation and any other relevant documentation in response to the noncompliance identified and any assessed penalty. Program management provides the Commissioners information on the compliance action that was issued to the operator, any alternative agreement that has been discussed with the operator, and management's recommendations to collect or reduce a penalty for noncompliance. According to PUC management, after the Commission reviews the information from the proceeding, it either issues a decision to approve management's recommendation, or if the Commission does not issue a decision within 20 days, then management's recommendation is enacted. Documentation for proceedings is maintained in the PUC's Electronic Filings system. During Calendar Years 2017 through 2022, the Program's records and proceeding documentation showed that the Program issued 25 operators a total of 28 compliance actions—5 written warnings, 21 notices of probable violations, and 2 other actions that resulted in the collection of penalties, as discussed further below.

The Program uses the federal Inspection Assistant (IA) system to document certain inspection results, such as the regulations that an inspected operator has not met and whether the noncompliance is classified as a concern or unsatisfactory. The Program also has a shared network drive where it keeps records of some compliance actions issued to operators. In Calendar Years 2020, 2021, and 2022 through November 2022, the Program utilized Smartsheet to maintain the State's detailed internal supporting documentation of inspections and the results; the Program replaced Smartsheet with OnBase in December 2022.

What was the purpose of the audit work and what work was performed?

The purpose of our audit work was to evaluate whether the Program has enforced operator compliance with gas pipeline safety requirements, in accordance with applicable federal laws, regulations, and guidelines promulgated by PHMSA; and state statute, regulations, and guidelines developed by the Program. We also assessed the extent to which the Program has sufficient processes to enforce safety requirements for operators with serious, repeat, or ongoing noncompliance. Program management was unable to provide a complete list of all compliance actions taken by the Program during Calendar Years 2017 through 2022, so the audit team compiled a list of the compliance actions that we were able to identify by reviewing: (1) the PUC's available documentation of all gas pipeline compliance proceedings, which was for Calendar Years 2019 through 2022; (2) five written warnings that the Program provided from information stored on its shared network drive; (3) grant progress reports that the Program sent to PHMSA in Calendar Years 2017 through 2022, which stated the number of compliance actions issued and civil penalties collected; and (4) records of collected penalties that the PUC recorded in the Colorado Operations

Resource Engine (CORE), the State's accounting system, in Calendar Years 2017 through 2022. To identify the inspections that documented operator noncompliance and/or Program follow-up steps that were taken to help ensure operators came into compliance, we reviewed: (1) documentation of PUC proceedings in Calendar Years 2019 through 2022; (2) the data that the Program recorded in IA for Calendar Years 2017 through 2022; (3) the Program's available internal data for Calendar Years 2020 through 2022; and (4) and documentation of operator noncompliance provided by the Program from its shared network drive.

In Calendar Years 2017 through 2022, the Program recorded conducting 98 different types of inspections in IA. Based on our analysis of the inspection data and PHMSA Guidelines [PHMSA Guidelines 2021, 5], we grouped the 98 inspections into six categories for the purpose of our analysis—(1) standard inspections, (2) integrity management, (3) damage prevention, (4) operator qualifications/training, (5) compliance follow-up, and (6) inspections/investigations of incidents/accidents. When analyzing the Program's inspection records showing operator noncompliance, we assessed the extent to which the Program issued enforcement actions to the operators for each of these six categories. We also interviewed Program management and staff to understand procedures and practices for enforcing safety regulations, and for documenting noncompliance and enforcement.

How were the results of the audit work measured?

A state agency that participates in the federal pipeline safety program must regulate safety standards and practices related to intrastate gas pipeline facilities and the transportation of that gas [49 USC 60105]. According to PHMSA Guidelines, a state's regulation includes "enforcement responsibility with respect to intrastate facilities" and the state "must provide for the enforcement of the safety standards" [PHMSA Guidelines 2018 through 2022, 2]. State statute and regulations have adopted federal pipeline safety standards [Section 40-2-115, C.R.S., and 4 CCR 723-11000 et seq.]. As such, we assessed the Program's processes and practices to enforce applicable federal and state requirements against the following criteria:

- **The Program must issue compliance actions to operators that are noncompliant.** States must pursue enforcement action substantially the same as those authorized by federal law [49 USC 60105, 49 CFR 198, and Section 40-2-115(1)(d), C.R.S.]. When an inspector identifies noncompliance, the Program must issue the operator a "compliance action," which is "an action or series of actions taken to enforce Federal pipeline regulations" [PHMSA Guidelines 2018 through 2022, Glossary]. A written compliance action detailing the probable violations shall be sent to the operator [PHMSA Guidelines 2021 and 2022, 5.1.5]. PHMSA's evaluations of state programs verify that a compliance action was sent for each probable violation. The compliance action that must be initiated by the Program is intended to remediate and prevent recurrence of the noncompliance [4 CCR 723-11502(a)]. State regulations define the types of compliance actions that the Program may issue, which are listed in order of least serious to most serious:

- Written Warning Notice—For an operator with no previous noncompliance history and a noncompliance that poses a low risk to public safety or pipeline integrity [4 CCR 723-11503].

- Written Request for Amendment—When an operator's plans or procedures may be insufficient to ensure compliance; this request may recommend or require the operator to revise and/or implement safety-related plans or procedures [4 CCR 723-11505].

- Written Notice of Amendment—For an operator with noncompliant procedures that must be changed quickly, sometimes immediately, if it could affect public safety or pipeline integrity [4 CCR 723-11506].

- Written Notice of Probable Violation—For operators with a history of noncompliance or noncompliance posing a moderate to severe risk to public safety or pipeline integrity [4 CCR 723-11504].

According to internal guidelines developed by the Program, "The most difficult aspect of an inspector's analysis is whether the information they gather during an [inspection] is a Concern or is truly Unsatisfactory" and "[i]nspection findings of "Unsatisfactory" or "Concern" have more complex compliance implications" because those findings need to be evaluated in order to determine what type of compliance action must be issued. The internal Program guidelines also note that minor noncompliance, which may be labeled as a "concern" in IA, should result in a written compliance action, such as a warning, that cites specific code sufficiently so that a pipeline operator may address the noncompliance. Other noncompliance, which may be labeled as "unsatisfactory" in IA, should result in a notice of probable violation. These internal guidelines state that "If the Inspector uses a Concern in lieu of Unsatisfactory for minor violations [i.e., noncompliance], it should only be used after considering all potential public safety and/or pipeline integrity concerns (risk) and the action being taken by the operator to correct the problem…and the operator's past performance for correcting apparent violations." [Colorado Program internal guidelines].

- **The Program must maintain a complete record of each compliance action** [PHMSA Guidelines 2018 through 2022, 5.1.6]. Current PHMSA Guidelines in place since the beginning of Calendar Year 2021, require the Program to keep records of all compliance actions for at least 5 calendar years plus the current year [PHMSA Guidelines 2021 and 2022, 8.3]; the Guidelines from Calendar Years 2018 through 2020 required the Program to maintain records for 3 years plus the current year [PHMSA Guidelines 2018 and 2020, 8.3]. "The State agency must keep records of all pipeline safety inspections and follow-up activities…[including] the regulation sections checked for compliance, and the resulting evaluation conclusions" [PHMSA Guidelines 2018 through 2022, 5.1]. The Program must maintain noncompliance records in order to identify and enforce continuous noncompliance of pipeline safety regulations [PHMSA Guidelines 2018 through 2022, 5.1]. State regulation defines a continuous noncompliance as a timeframe of noncompliance that can be established through physical evidence and/or records

[4 CCR 723-11001]. Maintaining complete records is also important because the Program is required to report all instances of noncompliance and compliance actions to PHMSA as part of its annual progress reports. PHMSA uses these reports to help evaluate the Program's performance and determine the Program's federal funding [PHMSA Guidelines 2018 through 2022, 2.7 and 5.1].

- **The Program must follow-up on compliance actions.** Compliance follow-up inspections are "inspections or evaluations to see if actions are completed as requested to an operator from a previous inspection or compliance action" [PHMSA Guidelines 2018 through 2022, 5.1.4 and .7]. The Program "must…have a review procedure that will ensure that proper and timely follow-up activity has been completed for each noncompliance" [PHMSA Guidelines 2018 through 2022, 5.1.6]. For example, if a warning compliance action is issued, follow-up inspections must be conducted to ensure remediation [4 CCR 723-11503]. According to PHMSA, "An important aspect of any State agency's compliance program involves the gathering of the necessary evidence for documenting noncompliance" [PHMSA Guidelines 2018 through 2021, 5.2]. The Program must also keep records of all follow-up activities for 5 years plus the current year; prior to 2021, this record retention requirement was 3 years plus the current year [PHMSA Guidelines 2018 and 2020, 8.3; and 2021 and 2022, 8.3]. "Follow-up records should include all correspondence or other contact between the State agency and the operator, the results of follow-up inspections, and other information necessary to demonstrate that the noncompliance has been corrected" [PHMSA Guidelines 2018 through 2022, 5.1.7]. Additionally, according to PHMSA, "After each inspection,…[c]opies of relevant operator records, statements from operator personnel, photographs, calculations, and all other data pertaining to each issue of noncompliance should be made a part of the documentation" [PHMSA Guidelines 2018 through 2022, 5.2].

- **Operators must be notified of all noncompliance through compliance actions.** Under federal law, as well as PHMSA Guidelines, after an inspection, the Program should notify the operator with a notice of the findings found in the inspection and "any actions being taken as a result of a finding of noncompliance" [49 USC 5101, et seq. and 5121, and PHMSA Guidelines 2018 through 2022, 5.1].

What problems did the audit work identify?

Overall, we found that the Program has not consistently enforced operator compliance with safety regulations, or followed applicable federal laws, regulations, and guidance, or applicable state statute and regulations, to ensure that operators comply with pipeline safety requirements. We identified the following problems:

- **Incomplete Program records of compliance actions.** The Program does not maintain information on compliance actions issued to operators in a centralized manner, nor has it retained all required documentation of compliance actions. When we requested Program information on compliance actions issued to operators, management provided five written warnings that were sent to operators in Calendar Year 2022, and a list of 21 notices of probable violations sent to operators and heard during PUC proceedings in Calendar Years 2019, 2021, and 2022. Management advised us to review PUC documentation of proceedings related to gas pipeline safety operators for more information on compliance actions. The Program Manager, who began working for the PUC in April 2021, was not aware of compliance actions issued prior to 2021 because the Program had not tracked information on them. Several Program management, inspectors, and staff, all of whom had been with the Program for 5 years or more, stated that they could remember only one compliance action issued prior to 2021. The PHMSA Guidelines from 2018 to 2020 required the Program to maintain records for 3 years plus the current year, meaning the records should have been available during the audit in 2022.

  Since the Program did not track or have complete documentation on compliance actions, we reviewed documentation of PUC proceedings, the Program's grant progress reports that stated the number of compliance actions and penalties collected each year, and CORE data. Our review identified a total of 28 compliance actions sent to 25 operators during Calendar Years 2017 through 2022; these 28 actions include the five written warnings and the list of 21 notices of probable violations that the Program provided. These 28 compliance actions also included two penalties that the Program assessed and collected in Fiscal Years 2018 and 2019, for which the Program did not have records of the specific compliance actions issued or information to explain the penalties.

  Additionally, on the Program's shared network drive, we identified information from 2017 and 2018, including compliance actions on PUC letterhead, showing that staff had recommended 26 compliance actions for operators for certain noncompliance during the time period, but the Program did not have records to indicate whether these actions had been approved by Program management and communicated to operators. As such, we could not determine if these were legitimate compliance actions that were issued to operators.

- **Lack of Program enforcement through compliance actions when operators are noncompliant.** According to Program documentation and data, the Program did not issue any written compliance actions for at least 5,280 of the 5,643 (94 percent) instances of concerns and unsatisfactory noncompliance that the Program documented for operators in Calendar Years 2017 through 2022. Due to a lack of documentation, we could not determine whether the Program notified the operators of the noncompliance verbally. Not issuing compliance actions for operator noncompliance is an area

> "*The Program did not issue any written compliance actions for at least 5,280 of the 5,643 (94 percent) instances of concerns and unsatisfactory noncompliance that the Program documented for operators in Calendar Years 2017 through 2022.*"

where PHMSA has identified ongoing Program noncompliance with federal requirements over the last several years. In Calendar Years 2019, 2020, and 2021, PHMSA's evaluations found that the Program did not issue compliance actions for all operator noncompliance that Program inspectors had identified, and PHMSA directed the Program to issue a compliance action for each instance of noncompliance. In each of these years, Program management agreed with the PHMSA findings.

For four types of inspections that the Program conducted, there were no compliance actions issued for much of the noncompliance identified by inspectors. Exhibit 2.5 summarizes the noncompliance with no associated compliance action, broken out by the type of inspection and showing the number of concerns and unsatisfactory noncompliance identified. For example, in Calendar Years 2017 through 2022, for 1,712 of the 5,280 (32 percent) instances of noncompliance identified where no compliance actions were taken, the Program documented that the noncompliance was unsatisfactory, and related to operator damage prevention and integrity management. These two types of noncompliance can be among the most serious because they indicate that the operators did not have sufficient plans or procedures, such as for emergency planning, pipeline corrosion control, and stress-cracking prevention, to help prevent outside forces from causing a catastrophic pipeline failure.

Exhibit 2.5
Summary of Operator Noncompliance without Associated Program-Issued Compliance Actions, by Inspection Type Calendar Years 2017 through 2022

Year	Number of Operators Inspected	Noncompliance by Inspection Type, without Compliance Actions							
		Integrity Management[2]		Damage Prevention[3]		Operator Qualification and Training[4]		Standard[5]	
		Concerns	Unsats	Concerns	Unsats	Concerns	Unsats	Concerns	Unsats
2017	12	79	421	N/A	61	13	N/A	51	110
2018	11	48	165	35	73	3	7	93	55
2019	7	310	212	234	9	N/A	49	105	20
2020	11	178	21	34	20	20	N/A	139	47
2021	3	39	44	11	54	8	N/A	87	8
2022	23	968	398	440	234	26	66	198	87
Total	**25 [1]**	**1,622**	**1,261**	**754**	**451**	**70**	**122**	**673**	**327**

Source: Office of the State Auditor's analysis of Program documents and federal IA data.
[1] Unduplicated count of operators inspected in the 6-year period, as some operators had multiple inspections.
[2] Integrity management inspections review the operator's approach to ensuring the integrity of its gas pipeline systems, and can include checking operator procedures to mitigate pipeline deterioration and leaks.
[3] Damage prevention inspections check operator plans and preventive measures for mitigating the effects of any activity that could damage a pipeline and cause a pipeline failure, such as in the event of a pipeline strike.
[4] Operator qualifications/training inspections check if an operator and its contractor staff meet minimum qualification requirements to perform their duties, such as related to pipeline facilities and maintenance.
[5] Standard inspections check areas, such as operations and maintenance records and plans, emergency procedures, pipeline facility control room management, public awareness plans, and drug/alcohol testing programs.

Furthermore, Exhibit 2.6 shows that, in Calendar Years 2017 through 2022, the Program issued few compliance actions to operators for noncompliance although a significant amount of noncompliance was documented. In these years, the 28 compliance actions were issued to 25 operators for noncompliance—7 public operators and 18 private master meter operators. According to Program management, one compliance action may cover multiple instances of noncompliance; however, due to a lack of Program documentation and data, we were not able to determine all instances of noncompliance that contributed to the Program issuing the 28 compliance actions, or determine whether or not the operators responded to all 28 compliance actions.

Exhibit 2.6
Summary of Known[1] Compliance Actions Assessed for Operator Noncompliance
Calendar Years 2017 through 2022

Year	Number of Operators Inspected	Number of Records of Documented Inspections of all Types [4, 5]	Documented Instances of Noncompliance Categorized as Concerns	Documented Instances of Noncompliance Categorized as Unsatisfactory	Number of Compliance Actions [1] Issued	Number of Operators Issued a Compliance Action [1]
2017	18	1,368	145	610	1	3
2018	16	400	239	300	1	5
2019	9	1,615	649	290	1	1
2020	14	391	371	88	0	0
2021	7 [2]	738	262	198	8	8
2022	42	4,425	1,672	819	17	16
Total	**59** [3]	**8,937**	**3,338**	**2,305**	**28**	**25** [3]

Source: Office of the State Auditor's analysis of PUC and Program documents and data and federal IA data.
[1] Compliance actions for which the PUC had documentation showing the actions were issued to the operator.
[2] For 2021, the Program recorded in the federal IA system that it inspected seven public operators, but had also conducted inspections of eight private master meter operators which were not recorded in IA.
[3] Unduplicated count of operators in the 6-year period, as some operators had multiple inspections or compliance actions.
[4] This column reflects Program records of the 98 different types of inspections that the Program conducted of all individual operator units. As noted in our *Inspections of Operators* Finding, the Program did not have complete records of inspections in 2017 through 2019; therefore, the numbers shown for those years are based on the limited records provided by the Program.
[5] According to the Department, the number of inspections varied during these years due to Program staffing. The Department reports that it conducted more inspections in 2022 compared to prior years because the Program was fully staffed.

According to PUC management, although improvements are needed related to Program enforcement, the Commissioners, and PUC staff who are outside of the Program, have approved some operators' planned investments in pipeline safety. The PUC has also provided some operators "expedited cost recovery" to mitigate safety risk for high-risk and critical operator assets. Expedited cost recovery means that the PUC has allowed some operators, such as Xcel Energy, to increase rates in order to begin recovering the cost of pipeline safety investments so that these investments are prioritized. For example, the Commission has approved for operators to replace and repair pipelines, and install valves that can shut off gas in pipelines automatically in an emergency.

- **Issued compliance actions do not always reflect the severity of operator noncompliance.** For five of the 28 compliance actions issued to four public operators—including Black Hills Energy, Colorado Springs Utilities, Sterling Ethanol, and Western Midstream—the Program only issued written warnings, the least serious type of compliance action, even though the inspection results demonstrated that a more serious compliance action was warranted because the inspectors had documented that the operators had a history of noncompliance or had noncompliance that posed a moderate to severe risk to public safety or pipeline integrity. According to state regulations, a more serious type of compliance action would have been appropriate for the types of noncompliance identified due to the repeat noncompliance and the risk posed to public safety.

The site of a September 2020 explosion in the Chatfield Corners neighborhood of Gypsum, Colorado.
Photo Credit: John LaConte, Vail Daily

Additionally, the Program did not issue a compliance action to a large public operator, Black Hills Energy, after the Program found that the operator was responsible for mismarking a pipeline, which led to the pipeline being struck and an explosion (see more information in Exhibit 2.8) that killed one person and resulted in catastrophic loss of property in Gypsum, Colorado, in September 2020. The Program also found that the operator failed to advise residents to evacuate. According to Program management, it issued a verbal warning to Black Hills Energy for noncompliance related to this accident and requested that the operator take corrective action to make safety improvements. Although the Program did not issue a written compliance action to this operator as a result of this accident, in Calendar Years 2021 and 2022, the Program did issue 18 written compliance actions for record keeping issues to private master meter operators—small operators that serve areas such as mobile home parks and apartment complexes—after inspections had found record keeping issues for these small operators. The Program's decision to not issue a written compliance action to the large public operator for its gas pipeline safety mistakes that resulted in a person's death, but to issue compliance actions to small private operators for record keeping issues, did not appear to be equitable.

Lastly, in Calendar Year 2022, three of the five written warnings that the Program issued had identified multiple instances of public operator noncompliance with regulations but they were not sent to the operators until months after the inspections. For example, for public operator Sterling Ethanol, the Program issued the written warning 4 months after inspections documented 22 instances of noncompliance; for public operator Black Hills Energy, the

Program issued the written warning 10 months after inspections documented nine instances of noncompliance. The Program's issuance of these compliance actions months after identifying noncompliance did not appear to be sufficient to help ensure that the instances of noncompliance were addressed by the operators in a timely manner.

- **More serious noncompliance is not classified consistently by the Program.** As shown in Exhibit 2.6, the Program did not consistently classify similar types of noncompliance as either a concern or as unsatisfactory. For example, the Program classified 2,497 of 4,273 (58 percent) damage prevention and integrity management instances of noncompliance as concerns although the noncompliance that the inspectors documented in IA indicated that the operators did not have sufficient procedures and plans to mitigate or prevent a catastrophic pipeline failure. According to PHMSA Guidelines, it may have been more appropriate for the Program to classify these types of noncompliance as unsatisfactory, in which case the Program would have needed to issue a notice of probable violation compliance action (which the Program did not issue). As another example, the Program classified one operator's lack of having emergency plans as an unsatisfactory noncompliance, but classified the same noncompliance due to lack of plans as concerns for seven other operators; no compliance actions were issued for any of these noncompliance instances. According to the PUC, classifying noncompliance consistently is difficult because operators may have some operations that are unique. Nonetheless, the Program should have processes to help ensure that inspectors generally classify similar noncompliance in a similar manner across operators and inspections.

- **Lack of proper and timely Program follow-up on noncompliance.** The Program did not have documentation to demonstrate that it had completed proper and timely follow-up on noncompliance identified during inspections. For example, in Calendar Years 2020 and 2021, the Program did not document that it had conducted any compliance follow-up related to three prior compliance actions issued to two large public operators that had repeat noncompliance—Xcel Energy and Colorado Natural Gas, shown in Exhibit 2.7 and in our *Penalty Assessment and Collection* Finding. Some Program records also noted that inspectors issued verbal warnings to operators for noncompliance, but did not indicate corresponding follow-up. For at least two of the 17 compliance actions that the Program documented in Calendar Year 2022, information from the Program's shared network drive showed that these operators gave verbal confirmation that they had not yet come into compliance but were working on it and the operators told the Program that they did not have any documentation showing their plans or have a timeline for when the noncompliance would be corrected. In addition, the inspectors did not observe compliance, such as by reviewing documentation to substantiate that the noncompliance was corrected. However, the Program documented that these operators made satisfactory progress toward addressing the noncompliance based on the verbal discussions.

Why did these problems occur?

- **The PUC's record retention policy conflicts with federal requirements for the Program.** Current Program management was unsure why former management had not maintained complete records of compliance actions from Calendar Years 2017 to 2019. According to Program management, former management may have deleted records because they had followed the PUC's record retention policy that was in place at that time, which was to maintain records for 3 years; however, the Program should have had 2019 records if it had followed PUC policy. Additionally, Program records from Calendar Years 2017 through 2022 should have been available at the time of our audit work because—from 2018 through 2020—PHMSA required Program records to be maintained for 3 years plus the current year, and in 2021, PHMSA began requiring the records to be maintained for 5 years plus the current year.

- **Lack of Program procedures to classify and document noncompliance consistently, and issue and document compliance actions for more serious, repeat, or ongoing noncompliance.** The Program's guidelines specify that inspectors should use discretion when classifying the results of inspections as concerns or unsatisfactory, but the Program has not developed sufficient guidance to help inspectors determine what types of noncompliance would constitute a concern and what would be considered unsatisfactory. Further, the Program's historical approach has been to give verbal warnings in lieu of compliance actions. According to Program management and staff, the historical practice and culture of the Program has been to consider operators as partners of the Program in helping to ensure safety compliance, and "trust but verify" that operators will become compliant after a Program inspector identifies noncompliance and issues a verbal warning. However, as described previously, our audit did not find evidence that the Program verifies that operators have corrected noncompliance when there are verbal warnings or for all written compliance actions.

  In addition, the Program does not have adequate procedures for determining the type of compliance action that is appropriate when noncompliance is identified—including more serious, repeat, or ongoing noncompliance—which can result in ongoing noncompliance, as discussed below. During the audit review period, the Program also lacked adequate procedures for notifying operators of warning compliance actions in writing, and following up to confirm that noncompliance has been corrected. Lastly, management has not developed a sufficient oversight process to help ensure that the Program generally issues compliance actions consistently based on the types and severity of noncompliance identified in inspections. During our audit, Program management drafted a process flow chart that roughly outlined a compliance action process, but our audit did not find that a process had been implemented to help ensure greater consistency in enforcement across inspections for similar types of operators or similar noncompliance, or for operator noncompliance that is more serious, repeat, or ongoing.

- **Lack of Program processes to help ensure proper and timely follow-up on noncompliance.** According to Program staff, they may not follow up to verify that noncompliance is corrected until the next standard inspection cycle, which could be up to 5 years after the Program inspects an operator and identifies noncompliance. Management and staff also told us that they sometimes rely on verbal comments from operators to determine if noncompliance has been addressed.

  Additionally, the Program may not have always conducted follow-up on noncompliance because inspectors have not consistently documented the inspection locations when recording each noncompliance. For example, for noncompliance related to equipment or a pipeline that inspectors observed, the Program did not always document the precise equipment or pipeline location, which would be needed for an inspector to be able to check that the noncompliance has been corrected. This issue is discussed further in our *Inspections of Operators* Finding.

- **Lack of information system capabilities to ensure compliance actions are tracked and issued.** Program management stated that it does not have a sufficient system to track the noncompliance identified for operators and the compliance actions issued to operators in the same location. Program information on compliance actions is maintained within the documentation of PUC proceedings, but a proceeding can include hundreds of pages of documentation. The Program does not maintain the compliance actions in a centralized file, database, or spreadsheet that management and staff can use to track and monitor each compliance action and the related follow-up that is needed or completed.
  In response to PHMSA's 2019 finding that the Program was not issuing compliance actions as required, the Program told PHMSA that it would begin using PHMSA's IA software to ensure that compliance actions were issued for instances of noncompliance identified during inspections. However, in September 2022, when PHMSA had a repeat finding that the Program had not issued compliance actions, the Program told PHMSA that it had not had a chance to make changes in response to the 2019 findings. According to Program management, as of March 2023, it was in the process of developing improvements to its new OnBase system to allow the tracking of instances of noncompliance in a manner that management could ensure compliance actions are issued; management did not have an estimated date by which these system changes would be in place.

Why do these problems matter?

- **When the Program does not enforce federal and state requirements for gas pipeline operators—or when enforcement is inconsistent—operator noncompliance persists.** For Calendar Years 2017 through 2022, we identified 14 public operators—larger operators serving 100 or more customers—that, according to Program inspections, had noncompliance continuing through multiple years, according to Program inspections, but these operators did not receive compliance actions from the Program. For example, the Program documented that over the 5-year period, Xcel Energy had 134 instances of noncompliance documented for 11 different regulations related to gas pipeline overpressure protection, which is intended to prevent pipeline pressure from exceeding a safe threshold to ensure safety when the pressure regulator fails or malfunctions; without gas pipeline overpressure protection a pipeline could rupture. Exhibit 2.7 summarizes the noncompliance for these 14 operators.

Exhibit 2.7
Public Operators with Multiple and Repeat Noncompliance for which the Program did not Issue Compliance Actions, Calendar Years 2017 through 2022

Operator Names	Number of Inspections	Number of Repeat Instances of Noncompliance Documented as Concern	Number of Repeat Instances of Noncompliance Documented as Unsatisfactory	Total Repeat Instances of Noncompliance
Xcel Energy	482	531	547	1,078
Colorado Natural Gas	175	464	102	566
Black Hills Energy	109	71	126	197
Atmos Energy Corporation	40	147	10	157
Rocky Mountain Natural Gas	43	57	74	131
City of Walsenburg	17	23	46	69
Town of Center	18	56	0	56
Ignacio Municipal Gas	14	21	32	53
Town of Aguilar	13	11	41	52
Sterling Ethanol	10	33	14	47
Fort Morgan Gas Dept.	10	12	19	31
Fountain Valley Power	6	21	0	21
Town Of Walden	5	14	0	14
Platte River Power	3	3	8	11
14 Operators	**945**	**1,464**	**1,019**	**2,483**

Source: Office of the State Auditor's analysis of PUC and Program documents and federal IA system data recorded by the Program.

- **Enforcement can help reduce noncompliance and the likelihood of accidents.** When operators remain noncompliant, the risk of endangering the public increases and operators may not have sufficient incentive to comply when there is a lack of Program enforcement. For Calendar Years 2018 through 2022, there were a total of nine safety accidents that were incidents or events (as defined by federal law and/or Program internal guidelines) that the Program investigated. These accidents related to intrastate gas pipelines for three public operators that the Program inspects—Xcel Energy, Black Hills Energy, and Atmos Energy Corporation. These operators had a history of prior noncompliance related to the areas or units that had been involved in the accidents, but the Program did not have evidence of issuing verbal or written compliance actions for most of this noncompliance. Exhibit 2.8 summarizes the nine accidents, the noncompliance that the Program's inspections identified with the same units in the same locations leading up to each accident, and any compliance actions that the Program issued to the operators for noncompliance in those locations in response to the accidents.

  According to PUC management, the Program may not have issued compliance actions related to the February 2022 Aspen, Colorado, accident listed in Exhibit 2.8, because the accident may not have related to the safety of gas pipelines, facilities, or underground storage, which is what the Program regulates. However, according to the PUC, the Program lacked documentation to prove or determine regulatory jurisdiction. Program records, including reports to PHMSA, showed that this accident related to gas pipeline safety when the Program investigated the accident.

Exhibit 2.8
Gas Pipeline Safety Accidents Related to Public Operators that were Not Issued Compliance Actions for Documented Instances of Noncompliance Prior to the Accidents, Calendar Years 2018 through 2022

Operator, Location of Accident, and Operator Unit Investigated	Accident Date	Damage From Accident	Number of Inspections of this Unit, 2017 to Accident Date	Unsatisfactory Instances of Noncompliance for this Unit, with No Compliance Actions Issued, 2017 to Accident Date	Concern Instances of Noncompliance for this Unit, with No Compliance Actions Issued, 2017 to Accident Date	Compliance Actions Documented, 2017 to Accident Date	Compliance Actions Issued Based on Accident	Operator Instances of Noncompliance From Accident Date through December 2022
Xcel Energy Salida Unit 86074	April 2018	Property Explosion—$151,130 in property damage, power outage for 3,900 people, area evacuated, and highway closure	29	5	0	None	None	76
Xcel Energy Aurora Unit 86080	November 2018	Home Explosion/Fire—1 fatality, 3 injuries, and several homes damaged or destroyed	45	10	6	None	None	30
Xcel Energy Breckenridge Unit 86083	April 2019	Home Explosion—2 injuries and 1 home destroyed	49	17	10	None	2 verbal warnings	39
Black Hills Energy Gypsum Unit 86059	September 2020	Home Explosion—1 fatality and 1 home destroyed	24	18	4	None	1 verbal warning	56
Black Hills Energy Glenwood Springs Unit 86059	December 2020	Gas Leak Due to Operator Error—$80,567 in property damage	24	18	4	None	None	56
Xcel Energy Buena Vista Unit 86074	February 2021	Pipeline Leak Due to Excavation Damage—$106,650 in property damage, and customers lost service	108	15	26	None	None	40
Xcel Energy Windsor Unit 86086	December 2021	Pipeline Rupture—$724,720 in property damage	104	15	19	None	None	0
Black Hills Energy Aspen Unit 86059	February 2022	Construction Site Explosion—4 people hospitalized and several others injured	43	41	14	None	None	23
Atmos Eaton Unit 86063	June 2022	Incident Unknown—2,500 homes and businesses lost power for 4 days	40	0	30	None	Notice of probable violation issued; $50,000 penalty assessed and reduced to $5,000	12

Source: Office of the State Auditor's analysis of available federal data, and state data and media reports, on gas pipeline incidents and events.
[1] This exhibit does not include the accidents that the Program did not have a record of investigating because operators failed to report the accidents. See our *Investigations of Safety Accidents* Finding for more details.

- **The Program's lack of enforcement can reduce public trust in the State's ability to ensure that operators comply with public safety standards.** Pipeline operators in Colorado operate in a regulated monopoly system that prevents the public from selecting how their natural gas is provided, and by whom. The public relies on the Program to ensure that utility operators are providing safe and reliable natural gas. According to PUC management, when regulating operators, the PUC must balance its efforts to enforce safety regulations for operators, with the possibility that operators may request increased rates for consumers in order to pay for the costs of making changes needed to comply with regulations. As discussed further in our *Penalty Assessment and Collection* Finding, statute specifies that the PUC should ensure that rate increases are just and reasonable [Section 40-3-101(1), C.R.S.], and operators may charge rates to consumers as long as the operators "provide and maintain such service, instrumentalities, equipment, and facilities as shall promote the safety…of its patrons…and the public" [Sections 40-3-101(1) and (2), C.R.S]. As such, the PUC may need to consider the impact that enforcing safety requirements may have on operators' costs, which may be passed on to consumers, as well as consider how enforcement will affect public safety.

- **The State could lose federal funding due to insufficient Program enforcement.** PHMSA annually evaluates state gas pipeline safety programs to help ensure that they enforce operators' adherence to federal safety regulations [PHMSA Guidelines 2020, 2.1]. For Calendar Years 2019 through 2021, when the Program did not issue compliance actions to operators for noncompliance, PHMSA reduced a portion of the Program's federal funding. For example, as discussed in Chapter 1, although the Program is generally eligible to receive a maximum reimbursement of up to 80 percent of expenses based on the availability of federal funding, PHMSA reimbursed Colorado's Program for 65 percent of its expenses in 2020, and 64 percent in 2021. When the Program's federal funding is reduced, it creates greater financial burden on the State and the PUC's Fixed Utilities Fund to pay a greater portion of Program expenses. Ultimately, repeat noncompliance by the Program could also affect the Program's certification to serve as the State's pipeline safety program on behalf of the federal government. [PHMSA Guidelines 2018 and 2021, 2.1].

Recommendation 2

The management and staff of the Public Utilities Commission should work with the Department of Regulatory Agencies to ensure that the Gas Pipeline Safety Program (Program) improves enforcement of federal and state gas pipeline safety laws and regulations by:

A. Developing and implementing Program procedures, and information system or database capabilities, to consistently classify and document operator noncompliance.

B. Developing and implementing Program procedures, and information system or database capabilities, to issue compliance actions when serious, repeat, or ongoing operator noncompliance is identified, and to help ensure enforcement consistency for similar types of operators and similar noncompliance. This should include procedures and capabilities to document all compliance actions and notify operators of warning compliance actions in writing.

C. Developing and implementing Program procedures to conduct appropriate and timely compliance follow-up for operators with compliance actions. This follow-up should review and document the extent to which operators have corrected noncompliance based on evidence of the operator actions to correct the noncompliance.

D. Implementing an oversight process to help ensure the Program follows the procedures to document and enforce operator compliance, and uses the information system capabilities, developed in response to Recommendation Parts A, B, and C.

Response

Public Utilities Commission and Department of Regulatory Agencies

A. Agree
Implementation Date: June 2024

The PUC will work with the Department to ensure that the Program improves enforcement of federal and state gas pipeline safety laws and regulations. The Governor's Office of Information Technology (OIT) is currently developing an application for the Program utilizing Hyland's OnBase platform. The application will provide tracking for compliance actions and the associated follow-up required, which include timelines that track operator response to compliance actions, compliance directives, and alternative enforcement choices. While implementation will begin under existing systems, full implementation will likely not be able to be completed until completion of systems development by OIT.

B. Agree
Implementation Date: June 2024

OIT is currently developing an application for the Program utilizing Hyland's OnBase platform. The application will provide tracking for compliance actions and the associated follow-up required, which include timelines that track operator response to compliance actions, compliance directives, and alternative enforcement choices. The OnBase platform will be used in implementing procedures to issue compliance actions when serious, repeat, or ongoing noncompliance is identified. Full and complete implementation is dependent on OIT.

C. Agree
Implementation Date: June 2024

OIT is currently developing an application for the Program utilizing Hyland's OnBase platform, which will be used in implementing procedures to conduct appropriate and timely compliance follow-up for operators with compliance actions. The application will include scheduled reminders to perform compliance follow-up inspections for operators with compliance actions. Full and complete implementation is dependent on OIT.

D. Agree
Implementation Date: January 2024

The PUC management and Program will implement oversight processes to ensure that the Program follows policies and procedures adopted and implemented.

Finding 3—Penalty Assessment and Collection

When the Program finds that an operator is in noncompliance, it has the regulatory power to enforce safety requirements through a compliance action, which can include issuing a monetary civil penalty (penalty) [49 USC 60122, and Section 40-7-113.5(1)(b), C.R.S.]. According to management and staff, the Program's historical approach to enforcement has been to give operators a warning of a future penalty if the noncompliance is not corrected and to maintain an open dialog with the operator to determine the best path forward to help ensure public safety is improved. In lieu of issuing a penalty to an operator, the Program may use what it refers to as "alternative enforcement," which entails management negotiating a compromise with the operator on how it should address the noncompliance to prevent a penalty from being assessed.

When the Program assesses a penalty, an operator has the option to pay the penalty or oppose the noncompliance in a proceeding or proceeding hearing. A proceeding is presided over by the PUC Commissioners, or they can assign an Administrative Law Judge, who adjudicates the matter on their behalf. The PUC Commissioners review the information provided by the Program, operator, and any other parties involved in the proceeding. If Program management believes that an assessed penalty is no longer needed to bring the operator into compliance, or that the operator has sufficiently addressed the noncompliance after the penalty is assessed, the Program Manager submits a written request to the PUC Commissioners recommending that the penalty be reduced or waived. The Commissioners decide whether to approve the recommendation based on information provided by the Program Manager.

According to the Program's and PUC's documentation, in Calendar Years 2021 and 2022, the Program assessed 20 penalties totaling $8.5 million to 20 operators, and ultimately collected a total of $5,000 in penalties. Most of these penalties were assessed for noncompliance by private master meter operators, which are entities that purchase gas service from a public operator, such as Xcel Energy, in order to deliver the gas to consumers whose aggregate usage is measured by a master meter, such as at an apartment complex.

What was the purpose of the audit work and what work was performed?

The purpose of our audit work was to evaluate whether the Program followed applicable federal regulations, state statutes, and PHMSA Guidelines for assessing penalties when operators are noncompliant with safety regulations. Program management was unable to provide a complete list of all penalties that the Program assessed and collected for Calendar Years 2017 through 2022, as discussed further below, so the audit team compiled a list of the assessed penalties that we were able to identify by reviewing: (1) the PUC's available documentation of all gas pipeline compliance proceedings for 2019 through 2022; (2) grant progress reports that the Program sent to PHMSA;

and (3) accounting records from CORE, the State's accounting system. We used the CORE records to determine the penalties that the Program collected.

To identify the inspections that documented operator noncompliance and had subsequent compliance actions, we reviewed: (1) documentation of PUC proceedings and decisions; (2) the Program's available state data recorded in Smartsheet, Excel, and OnBase in Calendar Years 2019 through 2022; (3) the data that the Program recorded in the federal Inspection Assistant (IA) system for Calendar Years 2017 through 2022; and (4) and documentation of operator noncompliance provided by the Program from its shared network drive. We interviewed Program management and staff to understand procedures and practices for assessing and collecting penalties.

How were the results of the audit work measured?

According to federal regulations and state statute, penalizing operators monetarily for noncompliance with gas pipeline requirements is a key regulatory tool available to the Program to bring operators into compliance and help ensure safety. We measured the Program's processes for assessing and collecting penalties based on the following requirements:

- **The Program may assess a monetary penalty to an operator for a compliance action** [49 USC 60122 and 4 CCR 723-11501]. Program management told us that it reserves the use of penalties for operators that routinely do not comply with safety regulations or that do not remedy their noncompliance. Federal regulations have established maximum penalty amounts that the Program may assess for operator noncompliance. In January 2012, federal law was updated to specify that operators are liable for penalties ranging from a not to exceed amount of $200,000 per day per violation/noncompliance to $2 million per day for a group or series of related violations, or instances of noncompliance, and to require that penalty assessment amounts be adjusted for inflation over time [49 USC 60122]. According to PHMSA, the penalties assessed by the Program must be "substantially the same" as those required by federal law [PHMSA Guidelines 2018 and 2021, 2.1]; however, PHMSA provided a letter to the Program stating that if the State had penalty amounts of $200,000 to $2 million, these amounts would be substantially the same as those amounts required by federal law, even if the State does not adjust penalty amounts for inflation.

  Prior to 2012, federal law had penalty amounts set at a minimum of $100,000 per day per violation/noncompliance and a maximum of $1 million per day per violation/noncompliance, which are the penalty amounts that are currently noted in Colorado's regulations [4 CCR 723-11501]. Senate Bill 21-108, which took effect July 6, 2021, required the PUC to update the penalty amounts that the Program assesses to align with the higher amounts that have been in federal regulations since 2012 [Section 40-7-117(1), C.R.S.]. As of April 2023, the PUC had not updated its regulations to reflect these new amounts, as required by statute, but PUC management and staff, said that they were in the process of working with the Commissioners to update state regulations. The increased penalty amounts that the federal government and the

General Assembly have established emphasize the importance of operator compliance with safety requirements, and the usefulness that penalties can provide to help ensure that operators comply with these requirements.

- **Penalty recordkeeping should be complete.** PHMSA Guidelines contain multiple provisions that emphasize the importance of state agencies maintaining complete records of Program operations. According to PHMSA, "Recordkeeping is vital to the operation of a pipeline safety program. State program files shall be well organized and accessible.... At a minimum [inspection records, including compliance action records] should be maintained by the State agency for a period of at least 5 calendar years plus the current calendar year;" a compliance action includes any action, such as assessing penalties, taken to enforce federal or state pipeline regulations [PHMSA Guidelines 2021, 8.3 and Glossary].

- **The Program must consider certain factors when assessing penalties.** Federal regulations require that the Program consider the following when assessing penalties: (1) The nature, circumstances and gravity of the noncompliance, including adverse impact on the environment; (2) the degree of the operator's culpability; (3) the operator's history of prior offenses; (4) any good faith by the operator in attempting to achieve compliance; and (5) the effect on the operator's ability to continue in business [49 USC 60122]. State regulations also require that the Program consider the operator's noncompliance and missing/incomplete records [4 CCR 723-11501].

- **The PUC may reduce assessed penalties based on certain factors, but penalties assessed after July 6, 2021, can be no less than $5,000.** Senate Bill 21-108 revised statute, effective July 6, 2021, to state that, if the PUC Commissioners approve a penalty reduction, "the amount of the penalty payable to the commission shall be no less than $5,000 dollars" [Section 40-7-117(2), C.R.S.].

  Further, statute requires that the PUC must consider the following "objective metrics and factors" when reducing any penalty: "(a) an evaluation of the severity of the violation, in terms of its actual or potential effect on public safety or pipeline system integrity; (b) the extent to which the violation and any underlying conditions that may have contributed to the likelihood or severity of the violation have been remedied; and (c) the extent to which the [operator] agrees to spend, in lieu of payment of part of the civil penalty, a specified dollar amount on commission-approved measures to reduce the overall risk to pipeline system safety or integrity" [Section 40-7-117(2), C.R.S.]. State regulations further require that, when the Program recommends a penalty reduction to the Commissioners, it must be "based on the operator's documented and verifiable efforts to mitigate the violations and [to] improve overall system safety and integrity…." [4 CCR 723-11501(f)].

- **Penalty warnings issued in lieu of penalties must be documented.** If the Program issues an operator a warning that a future penalty will be assessed if noncompliance continues, the warning must be in writing in a letter [PHMSA Guidelines 2018 and 2021, Glossary and 5.2]. The Program must also have procedures to: (1) ensure that the operator takes proper corrective action within a specific timeframe after notification of noncompliance [PHMSA Guidelines 2018 and 2021, 5.1.6], (2) determine the extent to which the operator agrees to spend an amount in lieu of payment of part of the penalty, and (3) determine the measures the operator will take to reduce the risk of noncompliance [Section 40-7-117, C.R.S.]. Therefore, it would be a best practice for the Program to document within the warning letter, the actions that the operator should take and the timeframe in which action must be taken.

What problems did the audit work identify?

Overall, we found that the Program has not consistently exercised the regulatory option, or followed applicable federal regulations and PHMSA Guidelines or state statute, to assess and collect penalties to help ensure that operators comply with pipeline safety requirements. We identified the following problems:

- **Incomplete Records of Penalties.** The Program did not retain documentation of all penalties assessed in Calendar Years 2017 through 2022. During our audit, Program management told us that during these years it had assessed only two penalties—one in 2019 assessed for $1.1 million and $5,000 collected, and one in 2022 assessed for $50,000 and $5,000 collected. In our review of PUC proceedings and decisions, the Program's grant progress reports, inspection data, and documents that staff had saved on the Program's shared network drive, and information in CORE, we identified 21 additional assessed penalties totaling $9.8 million, of which the Program collected a total of $198,530 for two of them. Our *Enforcement of Safety Regulations* Finding discusses the Program's lack of documentation of compliance actions for identified operator noncompliance.

- **Penalties typically not assessed when operators routinely do not comply with safety regulations or remedy their noncompliance.** Exhibit 2.9 shows that in Calendar Years 2017 through 2022, the Program assessed 23 penalties for 5,643 documented instances of operator noncompliance with federal regulations related to gas pipeline safety.

Exhibit 2.9
Summary of Known[1] Penalties Assessed for Operator Noncompliance
Calendar Years 2017 through 2022

Year	Number of Operators Inspected	Number of Documented Records of Inspections, for all Inspection Types	Number of Instances of Noncompliance Documented as Concerns	Number of Instances of Noncompliance Documented as Unsatisfactory	Compliance Actions[1] Documented	Number of Penalties[1] Assessed	Penalties[1] Assessed (Dollars)	Number of Penalties[1] Collected	Penalties[1] Collected (Dollars)
2017	18	1,368	145	610	1	1	$25,000	1	$25,000
2018	16	400	239	300	1	1	$1,267,590	1	$173,530
2019	9	1,615	649	290	1	1	$1,125,000	1	$5,000
2020	14	391	371	88	0	0	$0	0	$0
2021	7[2]	738	262	198	8	8[2]	$3,720,000	0	$0
2022	42	4,425	1,672	819	17	12[4]	$4,810,000	1	$5,000
Total	**59**[3]	**8,937**	**3,338**	**2,305**	**28**	**23**	**$10,947,590**	**4**	**$208,530**

Source: Office of the State Auditor's analysis of Program documents and federal IA data.
[1] The figures for compliance actions and penalties are based on the audit team's review and compilation of available documentation and data. The Program did not retain documentation of all compliance actions issued, or all penalties assessed and collected, between Calendar Years 2017 and 2022.
[2] For 2021, the Program recorded in the federal IA system that it inspected seven public operators, but the Program had also inspected eight private master meter operators and assessed penalties for those eight operators. The Program did not record the inspections of the master meter operators in IA for this year.
[3] Unduplicated count of operators inspected in the 6-year period, as some operators had multiple inspections.
[4] In 2022, 10 of the 12 operators that were assessed Program penalties were private master meter operators, and the remaining two were public operators. The Program submitted recommendations to the Commission to waive or reduce the 12 penalties assessed in 2022; however, in April 2023, management submitted a request to the Commission to rescind the recommendation to waive the penalties for six private master meter operators. According to the PUC, these proceedings were in progress as of April 2023.

Additionally, we identified the five operators that had the most instances of repeatedly failing to comply with safety regulations, or failing to remedy noncompliance in a timely manner, in Calendar Years 2020 through 2022, and assessed whether the Program utilized penalties to enforce compliance for these worst offenders, all of which were public operators. We selected these years for our review to determine if the Program has utilized penalties to regulate operators in recent years. As shown in Exhibit 2.10, the Program collected no penalties for any of these operators in Calendar Years 2020 through 2022—for four of the operators, the Program did not assess any penalties, and for the remaining operator that was assessed a penalty, the Program collected $0. For example, in 2022, during one inspection of six different locations for Colorado Natural Gas, Program inspectors documented 32 unsatisfactory instances of noncompliance with 33 federal regulations that were occurring in all six locations, but the Program did not assess a penalty. Unsatisfactory noncompliance for Colorado Natural Gas included not monitoring above ground pipelines for corrosion or leaks, and not having a process to identify existing and potential safety threats related to pipeline excavation damage and incident, leak, and maintenance history.

Exhibit 2.10
Known[1] Penalties for Operators with Multiple and Repeat Noncompliance
Calendar Years 2020 through 2022

Operator	Number of Documented Records of Inspections, for all Inspection Types	Number of Instances of Noncompliance Documented as Concerns in 2020–2022	Number of Instances of Noncompliance Documented as Unsatisfactory in 2020–2022	Number of Documented Repeat Concerns and Unsatisfactory Noncompliance	Number of Penalties[1] Assessed	Penalties[1] Assessed (Dollars)	Penalties[1] Collected (Dollars)
Xcel Energy	1,475	587	283	420	1	$100,000[2]	$0
Colorado Natural Gas	830	536	402	408	0	$0	$0
Black Hills Energy	628	292	147	211	0	$0	$0
Sterling Ethanol	101	127	69	93	0	$0	$0
Rocky Mountain Natural Gas	161	26	64	59	0	$0	$0
Total	**3,195**	**1,568**	**965**	**1,191**	**1**	**$100,000**	**$0**

Source: Office of the State Auditor's analysis of Program documents and data.
[1] The information on penalties is based on the auditor's review and compilation of available Program documentation and data.
[2] This penalty was assessed in September 2022, and this proceeding was still in progress as of March 2023.

Examples of repeat unsatisfactory noncompliance for the five operators listed in Exhibit 2.10 include:

- Operators not using appropriate coating or protection to prevent damage to pipelines, such as due to pipeline strikes during digging.
- Operators not correcting exposed pipelines over water crossings.
- Operators not checking gas meters and values to ensure there are no leaks or cracks.
- Operators using unqualified personnel or contractors related to "preventative and mitigative" safety measures, and pipeline corrosion control, which includes measures to ensure that pipelines can withstand gas pressure without rupturing.

- **Most assessed penalties are reduced, or not collected at all.** In Calendar Years 2017 through 2022, the PUC Commissioners approved reductions, as recommended by Program management, for 22 of the 23 penalties (96 percent) that the Program assessed operators for noncompliance. Additionally, from July 6, 2021, the effective date of Senate Bill 21-108, through December 2022, the Program recommended that the Commissioners reduce 19 of the 20 penalties assessed during this period to $0 in violation of the statutory provisions from the bill prohibiting reducing penalties below $5,000. In April 2023, after the audit team notified the PUC that these reductions would violate statute, the Program asked the Commissioners to rescind the Program's prior recommendations to reduce the remaining 6 of the 19 penalties, which were assessed to private master meter operators; these proceedings were still in progress as of April

2023. Exhibit 2.11 shows the penalty amounts that the Program assessed, compared to the penalties collected. Altogether, the Program could have collected $10.9 million in assessed penalties from operators from Calendar Year 2017 through Calendar Year 2022, but instead collected only $208,530, or 2 percent of the penalties assessed.

Exhibit 2.11
Comparison of Known[1] Penalties Assessed versus Penalties Collected
Calendar Years 2017 through 2022

Year	Number of Operators	Number of Penalties[1] Assessed	Penalties[1] Assessed (Dollars)	Number of Penalties[1] Collected	Penalties[1] Collected (Dollars)
2017	1	1	$25,000	1	$25,000
2018	1	1	$1,267,590	1	$173,530
2019	1	1	$1,125,000	1	$5,000
2020	0	0	$0	0	$0
2021	8	8	$3,720,000	0	$0
2022	12	12	$4,810,000	1	$5,000 [3]
Total	**21**[2]	**23**	**$10,947,590**	**4**	**$208,530**

Source: Office of the State Auditor's analysis of Program documents and data.
[1] The information on penalties is based on the auditor's review and compilation of available Program documentation and data.
[2] Unduplicated count of operators in the 6-year period.
[3] In 2022, the Program submitted recommendations to the Commission to waive or reduce the 12 penalties assessed. However, in April 2023, the Program submitted a request to the Commission to rescind the recommendation to waive the penalties for six private master meter operators, and these proceedings were in progress as of April 2023.

We conservatively estimated the amount of penalties that the Program could have assessed in Calendar Years 2020 through 2022, if the Program had applied the maximum penalties allowed by federal law and state statute for each documented instance of noncompliance. Our estimation was based on the penalties allowed, which include: (1) an assessed penalty of $200,000 per day, per noncompliance prior to any reduction, but not exceeding the maximum assessed penalty of $2 million, when the operator had a group or series of four or more instances of noncompliance, and (2) for each penalty that could have been assessed, a minimum reduced penalty of no less than $5,000 collected from the operator after July 6, 2021. Our estimate assumed that the operators would attempt to become compliant within 1 day of being assessed a penalty, based on the expectation that the penalties would serve their purpose in a relatively timely way. As shown in Exhibit 2.12, we estimated that for Calendar Years 2020 through 2022, the Program could have collected between about $2.4 million and $689 million in penalties for operator safety noncompliance that continued for 1 day, had the Program assessed and collected penalties in accordance with federal law and state statute. The estimated amounts would be higher if operators had a series of related instances of noncompliance or failed to come into compliance timely, because statute [Section 40-7-117, C.R.S.] specifies that each day constitutes a new instance of noncompliance.

Exhibit 2.12
Penalties the Program Could Have Assessed and Collected for Noncompliance
Calendars 2020 through 2022

Year	Number of Operators	Number of Documented Instances of Noncompliance	Maximum Penalties That Could Have Been Assessed for Individual Instances of Noncompliance	Maximum Penalties That Could Have Been Assessed for a Series of Noncompliance	Minimum Penalties That Could Have Been Collected After Allowable Reduction per Penalty
2020	87	459	$85,400,000	$127,000,000	NA[2]
2021	83	460	$82,600,000	$99,800,000	$415,000[2]
2022	402	2,491	$362,600,000	$462,400,000	$2,010,000
Total	**591**[1]	**3,410**	**$530,600,000**	**$689,200,000**	**$2,425,000**

Source: Office of the State Auditor's analysis.
[1] Unduplicated count of operators inspected during 3 years, as some operators received multiple inspections.
[2] Effective July 6, 2021, statute was revised to specify that, when the PUC reduces penalties, the penalty payable to the Program may not be less than $5,000 [Section 40-7-117(2), C.R.S.].

Exhibit 2.12 includes estimates of the penalties that could have been assessed and collected for the five public operators that are shown in Exhibit 2.10 and that had the most ongoing and repeat noncompliance in Calendar Years 2020 through 2022. Had the Program assessed penalties based on 1 day of noncompliance each, and collected the statutorily allowable penalty amounts, these five operators would have been required to pay between about $2.1 million (if only $5,000 had been collected for each penalty assessed) and $498 million (if maximum penalties had been collected for series or groups of related noncompliance), instead of the $0 in penalties that they paid.

- **Lack of evidence that the Program considered required factors when assessing and reducing penalties.** When the Program assessed 23 penalties in Calendar Years 2017 through 2022, we could not determine whether or not the Program considered all required factors for penalty assessment—such as the nature and gravity of the noncompliance, including impact on the environment, and the operator's culpability and history of prior offenses—due to lack of Program and PUC documentation. Also, when Program management recommended that the PUC Commissioners reduce or eliminate most of the assessed penalties after July 6, 2021, we could not determine whether or not the Program considered all of the required objective metrics and factors—such as the actual or potential effect on public safety, the specific dollar amount that the operator agreed to spend in lieu of paying of part of the penalty, and the operator's documented and verifiable efforts to mitigate the violations. According to Program management and staff, the reasoning for the penalty amounts that were assessed and the reduced amounts was based on verbal discussions between Program management and staff, and between the Program and the operators. However, the Program did not document whether the required factors in federal law, and in state regulations and statute were considered; the Program had documentation of the reasoning for the reduction of only one penalty in 2019. The reasoning for the 2019 reduction was that the operator, Colorado Natural Gas, had told Program staff that it would spend the amount of the assessed penalty to correct the noncompliance. However, the Program did not have evidence to show that the operator had corrected the noncompliance and, in fact, Colorado Natural Gas had the most repeat noncompliance in Calendar Years 2020 through 2022.

- **Undocumented penalty warnings.** Program management and staff told us that the Program has not consistently documented penalty warnings or provided operators a warning letter, as required by PHMSA Guidelines although some warnings have been discussed verbally with operators. We were able to confirm that verbal warnings were provided to some operators because some Program inspection records had inspector notes that said they provided a verbal warning. However, for these verbal warnings, there is no documentation of the actions that the operators should have taken to reduce the overall risk to pipeline system safety or integrity, or the timeframes within which the operators should have become compliant.

Why did these problems occur?

Historically, the Program has not penalized operators for violating federal regulations because Program management stated that it prefers to allow operators time to address their noncompliance problems, in lieu of paying a penalty. The Program also has not developed a process to review the inspection results to identify trends in repeat operator noncompliance, as we reviewed during this audit. Program management indicated that it does not find the review of aggregate inspection results for an operator to be useful, and it believes that inspectors are subject matter experts that can use their judgment to determine whether a penalty may be warranted based on institutional memory of noncompliance. As such, the Program has not developed sufficiently clear and consistent methods and internal guidance for determining when a penalty will be imposed—such as for certain types of noncompliance, or repeat or ongoing noncompliance over multiple years—or for determining when a penalty reduction is appropriate.

The Program has also not developed processes to document all penalties assessed and collected, or clearly document the rationale for the penalty amounts that are assessed or for the recommendations to the PUC Commissioners to reduce penalties. According to Program management, the penalty assessment process has been handled informally by staff and, when a penalty is assessed, staff often negotiate the amount of penalties to help maintain a positive and collaborative relationship with operators. Staff and the operators have verbal discussions of the noncompliance and the operators' plans or efforts to address it. When the Program Manager submits a written request to the PUC Commissioners recommending that the penalty be reduced, the request does not include details on the reasoning for the recommendation; the request states that the Program believes that the operator has sufficiently addressed the noncompliance. The Commissioners have consistently approved the recommendations. We were unable to determine the extent to which the Commissioners have asked questions about the reasoning for recommended reductions as the discussion has not been noted in meeting minutes.

Additionally, the PUC has not updated state regulations to mirror penalty requirements in federal regulations and state statute, as required by Senate Bill 21-108. As of April 2023, Program management stated that it was in the process of updating its written notices of probable violations that the Program sends to operators, and the documents that the Program provides the Commission, to reflect the penalty amounts in state statute. In March 2021, the PUC revised state regulations to specify that the Program shall calculate penalties through a formulaic method to provide consistency, and the method must include certain factors required by federal law and state statute [4 CCR 723-11501(d)]. However, as of March 2023, the Program had not yet implemented an objective method or processes to assess penalties in line with federal and state requirements, and Program management told us that the PUC was still working on revising state regulations to reflect the required penalty amounts.

Lastly, the Program has not had a process to consistently issue written penalty warning letters to operators because management has said that it wanted flexibility in how to assess penalties to operators for noncompliance. Management told us that, in March 2023, the Program started giving operators written correspondence of warnings.

Why do these problems matter?

Senate Bill 21-108 was passed in order to "strengthen and streamline Colorado's laws governing gas pipeline safety to meet emerging challenges" due to legislators' concerns over the Program's ability to keep up with safety inspections and enforcement. When the Program does not use its regulatory power to penalize operators to help ensure that they comply with safety regulations in a timely manner, the State is not sufficiently fulfilling its responsibilities to ensure that gas pipelines are safe. Specifically:

- **Not assessing penalties, or reducing them, can disincentivize operator action to address noncompliance.** A 2017 national study in pipeline safety found that operators were only motivated to comply with regulations when it is more expensive not to be in compliance; therefore, penalization is the primary driver of compliance in the economic model of utilities [Journal of Transport Economics and Policy Study, University of Bath, 2017]. By not assessing penalties and not documenting warnings of penalties, the Program disincentivizes operator compliance with pipeline safety requirements. As shown in Exhibit 2.10, the five operators with the most noncompliance between 2020 through 2022 were not penalized by the Program after it documented between 59 and 420 instances of repeat noncompliance by these operators, and some safety accidents occurred. For example, the Program's 2015 through 2017 inspection notes for Xcel Energy identified ongoing noncompliance related to the operator's procedures for pipeline maintenance and emergencies, mitigating corrosion control, and identifying and preventing leaks. The Program issued a written warning to the operator in October 2017 telling the operator that it was not sufficiently monitoring pipelines for leaks or taking prompt remedial action to correct deficiencies; the warning noted that the operator did not need to provide an official response to the warning, and the Program did not assess a penalty. In April 2018, the operator was responsible for an explosion that occurred when it was performing standard maintenance on a pipeline, found a gas leak, and the maintenance ruptured the pipeline. The explosion resulted in $151,000 in property damage and surrounding homes were evacuated. Since the 2018 explosion, the Program has documented that Xcel Energy has had a total of 1,247 instances of noncompliance throughout the state, and no penalties have been collected from Xcel Energy for the noncompliance as of March 2023.

Routinely reducing penalties can also disincentivize noncompliance. For example, in 2019 when the Program assessed a penalty of $1.125 million to Colorado Natural Gas for noncompliance, and reduced the penalty to $5,000, it did not appear to be an effective use of penalties to incentivize compliance because the Program's inspections of the same operator in 2022 documented 884 instances of noncompliance for over 70 different federal regulations.

- **Without evidence that penalties are assessed and reduced using consistent, objective factors, there is a risk of inequitable enforcement.** When the Program assesses or reduces penalties without evidence of following an objective, standard approach that considers the factors required by federal and state requirements, the State's regulation of operators could be inconsistent or give the appearance of being inequitable. For example, the Program assessed penalties against 18 private master meter operators in Calendar Years 2021 and 2022 after identifying noncompliance in the first inspections conducted of these operators, but did not assess penalties for four of the five public operators with ongoing and repeat noncompliance. According to Program management and staff, master meter operators are small and lack the resources of larger public operators. As such, it is unclear why these smaller operators had been assessed penalties when larger public operators have not been assessed penalties. The Program did not have documentation to show why the master meter operators were treated differently by being assessed penalties for record keeping errors, while larger public operators were not assessed penalties for repeat noncompliance.

- **Not documenting penalties decreases transparency, and could result in unallowable or unreasonable rate increases.** Statute states that the amount of a penalty *paid* shall not be an allowable expense for rate-making purposes [Section 40-7-113.5(1)(b), C.R.S]. For two penalties—$25,000 and $173,530—that the Program collected from Xcel Energy in Calendar Years 2017 and 2018, the Program did not retain internal documentation for the penalties, and there was no record that the penalties had been discussed in PUC public proceedings. The PUC Commission approved five rate increases for Xcel Energy between June 2018 and September 2020, but did not have any documentation to show that the rate increases were not based on Xcel Energy's expenses to pay its noncompliance penalties.

As a result of the Program's history of using undocumented penalty warnings and not providing the Commissioners with the reasons why management recommended penalty reductions and waivers, the PUC Commissioners may not have sufficient information to be able to consider an operator's existing or prior noncompliance when considering whether to approve operator rate increases. Statute allows operators to charge *just and reasonable* rates to consumers as long as the operators "provide and maintain such service, instrumentalities, equipment, and facilities as shall promote the safety…of its patrons…and the public, and as shall in all respects be adequate, efficient, just, and reasonable" [Sections 40-3-101(1) and (2), C.R.S]. Operators may recover operating expenses (e.g., labor, materials and supplies, pipeline maintenance and repairs, and contract work) by requesting a consumer rate increase from the PUC Commissioners, which they must approve so long as the rate increase appears to be just and reasonable [Sections 40-3-101(1) and 111(1.5)(b), C.R.S]. However, Commissioners may not be aware if an operator is rationalizing a rate increase based on its expenses to address safety noncompliance. For example, in Calendar Years 2020 through 2022, the Commissioners approved four rate increases for Colorado Natural Gas, which had the second most instances of repeat and ongoing noncompliance with safety regulations among all operators. Had the Program provided the Commissioners with written information on Colorado Natural Gas' ongoing noncompliance for these rate increase proceedings, it may have affected the Commissioners' decisions.

Recommendation 3

The management and staff of the Public Utilities Commission (PUC) should work with the Department of Regulatory Agencies to ensure that the Gas Pipeline Safety Program (Program) improves its assessment, collection, and documentation of civil penalties (penalties) when gas pipeline operators violate safety requirements by:

A. Updating state regulations/rules to be substantially the same as the requirements for penalty amounts in federal law and state statute. This should include ensuring that state regulations/rules reflect that the Program should apply the federally required penalty amounts.

B. Developing and implementing consistent, objective processes to assess and collect penalties for the operators that routinely do not comply with safety regulations as well as the operators that do not remedy noncompliance in a timely manner, and documenting the factors considered when determining the penalty amounts.

C. Communicating in writing to the PUC Commissioners the factors considered to justify the reasoning for each recommended penalty reduction, including the statutorily required factors, and communicating information on operator ongoing and repeat noncompliance, so that the Commission can consider the information before making decisions related to penalties and rate increases.

D. Developing and implementing processes to consistently document all penalties that the Program assesses and collects, and maintain penalty documentation.

E. Implementing a process to ensure that the Program consistently issues a written penalty warning letter to operators (when a warning is issued), and maintains the letters in line with record retention requirements. These letters should consistently document the corrective action that the operator must take to address the noncompliance, the timeframe for the action, any amounts that the operator agrees to spend in lieu of payment of part of the penalty, and the measures the operator will take to reduce the risk of noncompliance.

F. Implementing a process to ensure that the Program consistently updates its written notices of probable violations sent to operators to reflect the required penalty amounts.

Response

Public Utilities Commission and Department of Regulatory Agencies

A. Agree
Implementation Date: March 2024

The PUC will work with the Department to ensure that the Program improves its assessment, collection and documentation of penalties when gas pipeline operators violate safety requirements. The PUC and the Program are subject to statutory rulemaking processes. The PUC has an active rulemaking pending before the Commission in proceeding number 22R-0491GPS. Modifications to rules are proposed to match requirements of applicable federal and state laws. Only the Commissioners can approve the final rules, but we believe that the requirements of SB21-108 will be implemented as they are statutory requirements. Statutory penalty amounts have already been implemented administratively since March 2023.

B. Agree
Implementation Date: June 2024

The PUC will update the State Agency's written Program Guidelines to implement consistent, objective processes to issue notices of probable violations proposing assessment and collection of penalties for the operators that have demonstrated a history of noncompliance with safety regulations as well as the operators that do not remedy noncompliance in a timely manner. The Program will document the factors considered when determining the penalty amounts. Penalties assessed and collected will be documented in internal Commission systems and CORE.

OIT is currently developing an application for the Program utilizing Hyland's OnBase platform that will implement the Program's process to calculate and maintain penalty amounts and will apply them in the generation of Notices of Probable Violations. The PUC will work with OIT to ensure processes implemented are documented accordingly between that new system and the PUC's E-Filing System.

C. Agree
Implementation Date: March 2024

The PUC will update the State Agency's Program Guidelines to implement a process to ensure that every notice of probable violation served upon an operator will initiate a new proceeding before the Commission in the case management system, consistent with applicable federal and state regulations, as appropriate. The process will ensure that evidence will be presented to the Commission during the proceeding including the reasoning for any Staff recommendations to reduce or request the minimum $5,000 penalty proposed as well as instances of ongoing and repeat noncompliance by each operator upon whom the notice of probable violation was served.

D. Agree
Implementation Date: March 2024

The PUC staff will work with the Department to develop and implement a process to consistently document all penalties assessed and collected. Documentation of the penalties will be maintained in PUC systems and will be documented in CORE to demonstrate that collected penalties are accounted for consistent with such a process.

E. Agree
Implementation Date: March 2024

The PUC will update its formal compliance process in the State Agency's written Program Guidelines to include consistent use of the written warning letter to operators, which will include instances where no previous enforcement history and low risk to public safety has been determined. The warning letter will include the description of the probable violation, a compliance directive that will require the operator to correct the probable violation and may require a formal written response from the operator on the corrective action plan. The written Program Guidelines will include the requirements to maintain warning letters in line with record retention requirements.

F. Agree
Implementation Date: March 2024

The PUC will update its formal compliance process in the State Agency's written Program Guidelines as defined in applicable federal and state guidelines. The processes will consistently update the written notices sent to operators and implement penalty calculations based on the noncompliance identified consistent with applicable statutes and rules.

Finding 4—Inappropriate Recording and Misallocation of Program Penalty Funds

The Program may issue and collect penalties from operators when they violate federal and state requirements. The Department oversees all of the PUC's accounting processes, including how it records information on any penalties collected in CORE, the State's accounting system, and provides PUC staff accounting guidance. Based on limited information that the PUC recorded and documented in CORE, we were able to identify that the Program collected at least three penalties, totaling $203,530, from operators in Fiscal Years 2018 through 2022.

What was the purpose of the audit work and what work was performed?

The purpose of our audit work was to assess whether the PUC followed applicable statutes and rules when accounting for the penalty monies that were collected in Fiscal Years 2018 through 2022 that we were able to identify. We reviewed Program documentation, including its federal grant applications, to help identify the penalties assessed. We reviewed available CORE financial data and documentation to help identify penalties that were collected, and understand how the PUC accounted for and spent the penalty monies. We also interviewed the Department's current Controller and PUC management and staff to understand processes to account for the penalties that the Program collects.

How were the results of the audit work measured?

- **Collected Program penalties should be credited to the State's General Fund.** Section 40-7-113.5., C.R.S., outlines the penalties that are applicable to public utilities and requires that "penalties assessed pursuant to this section shall be paid and credited to the general fund, in addition to any other sanctions that may be imposed pursuant to law."

- **The Department should have proper accounting internal controls.** State Fiscal Rules require state departments to "implement internal accounting and administrative controls that reasonably ensure that financial transactions are accurate, reliable, conform to the Fiscal Rules, and reflect the underlying realities of the accounting transaction (substance rather than form)." [State Fiscal Rule 1-2 (3.5), *Internal Controls*]. An example of a proper accounting internal control is a process to ensure that all revenues are recorded in the correct accounting Funds. Accurate data are needed so that the State Treasurer can allocate revenues to state departments and programs based on statutory requirements.

What problems did the audit work identify?

Overall, we found that the PUC did not properly account for or document the penalty monies that the Program collected, which may have resulted in the PUC misspending state revenues. Specifically, we found:

- **Improper Accounting of Program Penalties.** We found that, in Fiscal Years 2018 and 2019, the PUC improperly recorded, and appeared to have misspent, at least $184,652 collected in penalties from an operator; this was 98 percent of the penalties that we were able to determine had been collected in those years. The PUC improperly recorded the $184,652 to the Department's Legal Services Offset Fund, instead of the State's General Fund, which commingled funds with different statutory purposes and, therefore, violated statute and State Fiscal Rules. By statute, the purpose of the Legal Services Offset Fund is to offset the costs of legal representation of the PUC's Transportation Section in proceedings related to the enforcement of motor carriers [Section 40-7-118(1)(a), C.R.S.]. Department management, including the Controller, and PUC staff could not confirm how many times this improper accounting of penalties had occurred and the extent to which the Program penalty funds were spent on unallowable purposes due to the commingling of the funds.

  According to the Department, the $184,652 in inappropriately allocated and recorded funds were ultimately transferred to the General Fund during the fiscal year-end closing processes in 2018 and 2019 because the Legal Services Offset Fund was exceeding its cash fund balance limit for those years. Statute requires that any Legal Services Offset Fund balance over $250,000 be transferred to the General Fund, which included these penalty amounts [Section 40-7-118(2), C.R.S.]. Therefore, the Department inadvertently corrected its error when the funds were transferred to the General Fund due to the excess cash fund balance.

- **Incomplete Penalty Records.** During the audit, Program management and staff initially told us that, from Fiscal Year 2018 through Fiscal Year 2022, the Program had collected only one penalty of $5,000, which was in Fiscal Year 2020. However, we were able to identify that the Program collected at least two additional penalties during the review period because the Program-prepared federal grant applications indicated that penalties of $25,000 and $173,530 were collected in Fiscal Years 2018 and 2019. The Program was unable to provide information on the operator that paid these penalties or the reasons that the penalties were assessed. Our *Penalty Assessment and Collection* Finding has more information on the Program's incomplete internal tracking of assessed and collected penalties.

  Additionally, we identified problems when we reviewed the information in CORE for all penalties that had been recorded and collected by the PUC. Specifically, for 81 of the 318 penalties (25 percent) that all of the PUC's sections, including the Program, recorded in CORE for Fiscal Years 2018 through 2022, we could not identify the purpose of the penalty collected or the source of the revenue because PUC staff did not record complete information in CORE.

For example, for all penalties, the data field indicating which PUC section collected the penalty was left blank; it was unclear why it was left blank for penalties given that PUC staff record the PUC section in other types of accounting records, such as payroll and operations expenditures. Additionally, data fields indicating the name of the operator or utility who paid the penalty were blank or listed nondescript names, such as "MISC VENDOR." As a result, it is not possible to use CORE's data reports to identify which penalties the Program had collected and which were collected by other PUC sections. Furthermore, the PUC has not consistently uploaded supporting documentation into CORE, such as PDF attachments of penalty letters sent to operators or payment checks the PUC received from operators, to help support the source and purpose of the penalties. Therefore, it is not possible to precisely determine how much in penalties that each PUC section collected, from whom, and for what purpose.

Why did these problems occur?

The problems that we identified related to the PUC not properly accounting for or documenting the penalties that the Program collected, occurred for the following reasons:

- **Former Department management gave the PUC improper direction to account for penalties.** PUC staff reported to us that Program penalty funds were not properly recorded and deposited into the State's General Fund because, in 2018, the Department's former Controller instructed the PUC to record and allocate the Program's collected penalty money to the Department's Legal Services Offset Fund for a time. Current Department and PUC management acknowledged that the penalty funds that we identified were inappropriately allocated and recorded, but they were unable to determine why the former Controller had directed staff to account for Program penalties improperly. Management indicated that they believed the inappropriate allocations and recording were a temporary mistake because of possible confusion about the purpose of the Legal Services Offset Fund, which was created in 2017 and was relatively new at the time these problems occurred, and because staff may have been more familiar with accounting for the Transportation Section penalties compared to the Program's penalties.

- **Improved internal accounting controls are needed to ensure penalties are properly recorded.** Although the misallocated penalty revenues that we identified were ultimately transferred to the State General Fund due to the balance limit on the Legal Services Offset Fund, the misallocation of Program penalties was not identified by the Department and purposefully corrected when it first occurred in Fiscal Year 2018. The Department has not implemented sufficient processes to periodically review the accuracy of the PUC's accounting of the penalties that its sections collect, and reconcile the PUC's internal penalty records and CORE data to help ensure that the PUC records penalty information accurately and completely.

Additionally, the Department may need to review supplemental financial documentation that the PUC may have uploaded into CORE, to help obtain information on the source and purpose of the various penalties that have been collected, and ensure that they were recorded correctly. However, this review may not provide complete information given that the PUC has not consistently uploaded supporting documentation into CORE, and it would be a manual and lengthy process.

Why do these problems matter?

- **Misrecording of State General Fund monies can lead to misspending.** When state revenues are not properly deposited into the State General Fund in a timely manner, as required, they can be misspent. As a result of the inappropriate allocations and recording, in Fiscal Years 2018 through 2022, at least $184,652 in penalty funds were made available for the PUC's Transportation Section to spend, in violation of statute, which limited the funds available for the state programs and services that relied on the General Fund in those years.

- **Risk of fraud or abuse.** Although we do not have any evidence that fraud had occurred, when the PUC does not consistently maintain complete and accurate records of the penalties that it collects, there is a risk that staff could fraudulently record and spend the state revenues for purposes that do not align with statute. Furthermore, part of the Department's mission is to ensure that "each and every one of the Department's employees contributes daily to ensuring that Coloradans are able to trust those who provide them with services." When the Department and PUC do not follow statute and State Fiscal Rules to account for state revenues, it can weaken public trust.

Recommendation 4

The management and staff of the Public Utilities Commission (PUC) should work with the Department of Regulatory Agencies to strengthen internal controls over the recording and accounting of the civil penalty (penalty) revenues collected by:

A. Developing and implementing a process to ensure that the PUC maintains complete and accurate internal records of the penalties assessed and collected by the Gas Pipeline Safety Program.

B. Strengthening processes to ensure complete and accurate recording of penalty information in the Colorado Operations Resource Engine (CORE), including information on the Gas Pipeline Safety Program penalties, so that penalty revenues can be deposited into the correct Funds. This should include implementing a periodic reconciliation of the PUC's internal penalty records with CORE's aggregate reports.

Response

Public Utilities Commission and Department of Regulatory Agencies

A. Agree
Implementation Date: July 2023

The PUC will work with the Department to strengthen internal controls over the recording and accounting of the civil penalty revenues collected. A procedure has been finalized to ensure that the PUC maintains complete and accurate internal records of penalties assessed and collected after the Commission determines the penalty amount. This procedure will be implemented starting July 1, 2023. It will document current accounting processes; provide for uploading the receipt from penalty payments to CORE, in addition to current documentation; and to create revenue source codes in CORE that correlate with the programs that are collecting the penalties. The additional chart of account elements will allow for more efficient reporting from CORE and reconciliation with case management systems.

B. Agree
Implementation Date: July 2023

The procedure [noted in Part A] documents accounting processes to ensure penalty revenues are deposited into the correct Funds starting July 1, 2023. The procedure will provide for uploading each receipt from penalty payments to CORE, in addition to current documentation; and create revenue source codes in CORE that correlate with the programs that are collecting the penalties. The additional chart of account elements will allow for more efficient reporting from CORE and periodic reconciliation with internal systems.

Finding 5—Investigations of Safety Accidents

When an intrastate gas pipeline hazardous accident occurs, such as an explosion or gas leak that could endanger the public, operators are required to report the accident to the Program. Operators must also report the types of accidents listed below to federal entities, such as the Environmental Protection Agency's National Response Center (NRC), which is the federal agency that receives reports of accidents related to natural gas. The gas pipeline industry, and federal and state regulations, refer to a gas pipeline safety accident as either an incident or an event, depending on the severity of the accident. As described below, an incident can be more serious than an event, and these terms are defined as follows:

- **Incident** is a pipeline, storage, or facility gas release that results in any of the following: death or injury requiring hospitalization, property damage of $122,000 or more, unintentional gas loss of 3 million cubic feet or more, or an emergency shutdown of a facility [49 CFR 191.3]. An incident is also any accident that results in unintentional fire or explosion, or property damage and the cost of cleanup exceeds $50,000 [Colorado Program internal guidelines], or that the operator determines is significant, even if it does not meet the criteria above [49 CFR 191.3].

- **Event** is a pipeline system emergency that results in any of the following: evacuation of 50 or more people from a normally occupied building or property, or of four or more residential structures; closure of a roadway or railroad; service outage for 100 or more customers; soil contamination cleanup (soil vapor extraction) of a pipeline leak exceeding 48 hours; or a pipeline that exceeds pressure limits and requires operator follow-up action such as an examination for leaks [4 CCR 723-11102(b)].

According to management, the Program monitors the NRC's website for any reports made by operators of accidents that have occurred, and monitors news media stories of gas pipeline accidents, to identify those in Colorado that operators may not have reported to the Program so that the Program can investigate. According to Program management and staff, after an accident occurs, the primary goal is to ensure no further loss of life, injuries, or property damage. After the location is secured by the operator and first responders—such as by shutting off the supply of gas to the location and mitigating any fire or leakage that could cause further damage—the operator should coordinate with law enforcement and the Program to plan and conduct an investigation into the accident's cause.

In May 2021, the Program's new Manager began tracking accidents and related investigations that occurred. From May 2021 through December 2022, the Program documented that it received 219 operator reports of accidents that were within the Program's jurisdiction, and documented that the Program investigated all of them. The Program did not have documentation of accidents, or the related investigations that may have occurred, prior to May 2021.

What was the purpose of the audit work and what work was performed?

The purpose of the audit work was to determine if operators reported intrastate gas pipeline accidents to the Program, as required, and if the Program complied with federal and state requirements for investigating accidents within its jurisdiction timely. We reviewed a listing of the accidents that the Program reported to PHMSA on grant progress reports for Calendar Years 2017 through 2022; Program inspection records recorded in Smartsheet noting inspections related to accidents in Calendar Years 2020 through April 2021; and available Smartsheet data on operator reporting of accidents to the Program, and Program investigations, for May 2021 through December 2022. We also reviewed the public data on NRC's website showing accidents that operators reported to NRC for Calendar Years 2017 through 2022 and reviewed news media stories of accidents occurring during these years. In December 2022, we observed one Program investigation of a gas pipeline explosion accident, and interviewed Program management and staff, operator staff, law enforcement, the property owner, and other neighborhood residents who were involved in the accident and on the scene during the investigation. We interviewed Program management and staff to understand their processes for operator reporting, and Program practices for conducting and documenting their investigations.

How were the results of the audit work measured?

The Program is responsible for investigating accidents related to intrastate gas pipelines and facilities to determine the cause of any safety failures, as follows:

- **Operators must report safety accidents to the Program and NRC.** When a gas-related safety accident occurs that meets the definition of an incident, the operator must report it to the NRC within 1 hour of discovery [49 CFR 191.5]; the operator must report accidents that are events to the NRC within at least 2 hours of discovery, and report all incidents and events, including any reported to NRC, to the Program within at least 2 hours of discovery [4 CCR 723-11102]. An operator's lack of reporting of an accident, as required, is considered noncompliance for which the Program may assess a penalty [4 CCR 723-11500].

- **The Program should investigate accidents.** PHMSA Guidelines [2018 through 2022, 1.3, 4.1, and 6], state regulations [4 CCR 723-11013(c)] and Program internal guidelines require the Program to investigate *each* accident (i.e., incidents and events) related to intrastate gas pipelines, facilities, and underground storage that is significant and/or that is reported to the NRC or the Program. According to PHMSA Guidelines, the Program must first conduct a telephone investigation of each gas-related accident reported to NRC that operators should have also reported to the Program; the goal is to initiate an investigation timely [PHMSA Guidelines 2018 through 2022, 6.1]. The purpose of this telephonic investigation of accidents reported by the operators that the Program regulates is to determine if the accident itself is within the Program's jurisdiction and related to the safety of gas pipelines, facilities, and storage. The Program must also either conduct an on-scene investigation or obtain sufficient information by other means to determine the facts and support the decision to not go on site [PHMSA Guidelines 2021 and 2022, 6.2 and 6.4]. As such, there is not always an on-scene investigation, but the Program must have evidence to demonstrate that it obtained sufficient information about the accident by other means and to support the decision to not go on site.

- **Program investigations should be reasonably timely to protect the public and determine cause.** The Program's internal guidelines state that the Program's initial investigative response to an accident should: (1) start within 72 hours of the Program being notified of the accident, (2) seek to determine the emergency response taken by the operator and local emergency responders to respond to the accident, (3) confirm that the operator has performed an immediate system safety check, and (4) conclude on whether the site is safe for the public [Colorado Program internal guidelines]. PHMSA and the Program have not established a timeframe for conducting the on-scene investigation or for completing investigations to determine cause; however, PHMSA Guidelines state that the primary objective of investigations is to identify the probable cause, minimize the possibility of recurrence, and institute enforcement action for operator noncompliance with the safety standards [PHMSA Guidelines 2018 through 2022, 6.1]. The Guidelines also specify that state program staff must be familiar with basic investigative procedures [PHMSA Guidelines 2018 and 2020, 6.2; and 2021 and 2022, 6.3], which generally include collecting evidence at the scene before it is disturbed or changed. As such, it is reasonable for the Program to have processes to ensure that it conducts an on-scene investigation in a sufficiently timely manner, so that the Program can review the on-scene evidence of an accident, determine the cause, minimize recurrence, and ideally, minimize the effects of the safety accident on the public.

- **The Program must retain all accident investigative reports for at least 5 years.** PHMSA Guidelines specify that each state agency should keep adequate records of operator notifications of all accidents received [PHMSA Guidelines 2018, 6.3; and 2020 through 2022, 6.4], and, at a minimum, accident investigative reports should be maintained by the state agency for at least 5 calendar years plus the current year; the Guidelines from 2018 and prior required the Program to maintain documentation of these investigations for 3 years plus the current year [PHMSA Guidelines 2018 through 2022, 8.3]. The Guidelines also state that, "Investigations shall be thorough with conclusions and recommendations documented in an acceptable manner" [PHMSA Guidelines 2018, 6.3; and 2020 through 2022, 6.4].

What problems did the audit work identify and why do the problems matter?

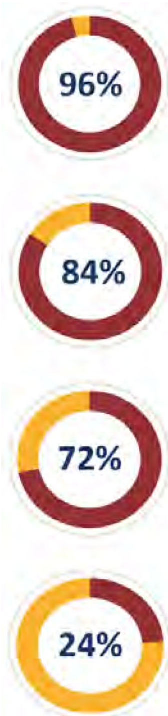
Overall, we found that the Program did not follow federal and state regulations for investigating intrastate gas pipeline accidents and documenting the investigations, and did not conduct investigations timely, as described below.

- **Lack of evidence that the Program was notified of, and investigated, accidents that occurred prior to May 2021.** We could not determine if the Program was notified of and investigated all accidents that occurred during Calendar Years 2017 through April 2021, as required. When we requested Program records of operators' reports of accidents and of the Program's related investigations, management said that this information was not available for Calendar Years 2017 through April 2021. The PHMSA Guidelines from 2018 to 2020 required the Program to maintain records for 3 years plus the current year, and the 2021 Guidelines required maintaining records for at least 5 years, so records of operator reporting and Program investigations should have been available during the audit in 2022 and 2023.

  Because the Program could not provide information on the accidents and associated investigations that occurred prior to May 2021, we reviewed the Program's annual federal grant progress reports and were able to identify 11 accidents that the Program reported to PHMSA during Calendar Years 2017 through 2019. We also reviewed Program inspection records from Smartsheet for Calendar Years 2020 through April 2021 (records were not available or were incomplete prior to Calendar Year 2020 as discussed in our *Inspections of Operators* Finding), in which the Program noted that 64 inspections were related to accidents. However, the data did not always document the operators involved or details of the accidents, such as when and where they occurred, when the operator arrived on-scene or notified the Program, or the resulting casualties and property damage. The inspection data also did not include information related to the Program's investigations, such as when they occurred, what type of investigation occurred (e.g., on-site or remote), or the cause or noncompliance identified. The Program also did not have any investigative reports for Calendar Years 2017 through April 2021, or have records to indicate the timeliness of the operator reporting to the Program. As such, we could not determine if the Program investigated the 75 accidents that we identified.

  When the Program does not have evidence that it was notified of accidents or has investigated them, as required, it appears that the Program is not fulfilling its responsibility under its federal grant to regulate operators to ensure they meet safety standards in a manner that helps protect the public. For example, the Program lacks evidence that it has investigated to identify operator noncompliance related to accidents and minimize the possibility of accident recurrence. Additionally, when the Program does not retain investigation records, it cannot use the information to assess operator safety and compliance with safety regulations over time and use the information to issue compliance actions for operators. This could result in ongoing operator noncompliance—as discussed in our *Enforcement of Safety Regulations* Finding—and further serious accidents occurring that put the public's safety at risk.

- **The Program lacks complete investigation records for May 2021 through December 2022.** From May 2021 through December 2022, when the Program began tracking information related to accidents and investigations, the Program documented 219 accidents that operators reported and that the Program investigated. However, the Program did not track complete information about the accidents or the investigations. For example, we found that Program data were missing the following key information for the 219 investigations:



No Inspector Information
For 211 of 219 (96 percent) investigations, the Program inspector assigned to the investigation was blank.

No On-Scene Investigation Information
For 183 of 219 (84 percent) investigations, there was no information indicating that the Program conducted an on-scene investigation, as required.

No Cause Information
For 157 of 219 (72 percent) investigations, the cause of the accident was not documented.

No Location Information
For 52 of 219 (24 percent) investigations, the accident's precise location, such as the address, was not documented.

When the Program does not maintain complete records, it does not have the information that may be needed to conduct follow-up inspections of operator compliance, and management cannot ensure that investigations followed federal and state requirements.

- **Operators did not report 54 gas-related accidents that occurred during Calendar Years 2017 through 2022.** Our review of NRC records and news media reports identified intrastate gas pipeline-related accidents in Colorado that Program-regulated gas pipeline operators did not appear to report to the Program, as follows:

  - 47 gas-related accidents that operators reported to NRC, but the Program had no record of receiving these reports from operators. Operators had reported 5 of the 47 accidents to NRC after the Program began tracking the details of accidents, but the Program had not documented these 5 accidents. The news media also reported on 5 of these 47 accidents.

  - 7 gas-related additional accidents that were reported by the news media, but neither the Program nor NRC had records of receiving these reports from operators.

The 54 accidents that operators did not report to the Program, and that lacked investigation records, included an explosion and gas pipeline leaks due to operator error, equipment failure, or pipeline overpressure. Examples of accidents that operators did not report to the Program include:

- In June 2022, the NRC received a report from Xcel Energy that a gas leak had occurred in Denver, Colorado, due to unknown reasons. The caller stated that 150 people had to be evacuated.

- In June 2022, the media reported that Atmos Energy Corporation had shut off the natural gas to the town of Eaton, Colorado, for 4 days, and more than 2,500 homes and businesses were affected. Program records did not include details of the investigation of this accident, but the Program did have a record of inspecting of Atmos Energy Corporation in June 2022, and penalized this operator for not reporting the accident to the Program.

Town of Eaton, Colorado.
Photo Credit: Charles M. Sauer, Wikimedia Commons

November 2020 explosion, Colorado Springs, Colorado.
Photo Credit: Colorado Springs Fire Department

- In November 2020, the NRC received a report from Colorado Springs Utilities that an explosion and fire had occurred in Colorado Springs, Colorado, when electrical service was being repaired near the gas pipeline. This operator stated that the explosion caused a crew member to sustain injuries requiring hospitalization, and seven homes were evacuated.

September 2020 explosion at residence in Morrison, Colorado.
Photo Credit: 9NEWS

- In September 2020, the NRC received a report from Xcel Energy that a private residence in Morrison, Colorado, had exploded and was on fire due to a release of natural gas. This operator stated there was one fatality.

At the end of our audit, PUC and Program management indicated that some of these accidents may not have been related to gas pipeline safety, which could be why the operators did not report them to the Program. However, three of the accidents were reported to the NRC, and the NRC reports at the time of the accidents showed they were gas-related; therefore, these accidents should have been reported to the Program, as required by Colorado regulations. As noted previously, the fourth accident was gas-related, and the Program penalized the operator for not reporting the accident, as required.

When an operator does not report accidents to the Program or NRC, as required, the Program may not be aware that it needs to begin an investigation to determine whether the accident was caused by the operator's negligence or noncompliance with safety requirements. As such, this limits the Program's ability to take enforcement action to help ensure the operator meets requirements, and has procedures to prevent additional accidents in order to keep the public safe. The Program did not have any documentation to show that it had investigated 53 of these 54 accidents, or had assessed whether or not the accidents related to the Program's jurisdiction of gas pipeline safety. Program management indicated that it was looking into these accidents at the end of our audit. Without evidence that the Program reviewed or investigated each of these accidents when they were reported to the NRC or when they had occurred, the Program cannot demonstrate that it took required action related to these accidents when they occurred.

- **Some operators do not report accidents timely.** From May 2021 through December 2022, seven operators did not report a total of 106 accidents to the Program within 2 hours of discovering the accident, as required. Specifically, Program records showed that the operators reported these 106 accidents between at least 1 day and 223 days after the accident date, or an average of about 98 days; 86 of the 106 accidents were reported by operators 7 days or more after the accident. Program management told us that an operator may not meet required timelines for reporting accidents if the operator did not "discover" information about an explosion timely, such as if the operator does not determine the amount of damage caused by an explosion until a week after the incident, but later determines that the accident meets the definition of a reportable accident. However, the reporting requirements are intended to ensure that operators report accidents that may be deemed significant, such as explosions, within hours of discovering the accident, and not after discovering the damages caused. When operators do not report accidents to the Program timely, the Program cannot begin an investigation while evidence is still fresh, to help ensure that the public is safe and that operators are appropriately sanctioned for any noncompliance that may have caused the accident to occur.

- **The Program does not track investigation timeliness.** We were unable to determine the Program's timeliness in initiating or conducting investigations of accidents. First, for the 75 accidents that we identified in Program federal grant progress reports and inspection records for Calendar Years 2017 through April 2021, there was not sufficient information to determine the extent to which Program investigations occurred or when they occurred. Second, for the 219 investigations of accidents that the Program conducted from May 2021 through December 2022, the Program did not document the dates the investigations were initiated or conducted. For example, we could not determine if the Program initially responded within 72 hours after the operators reported the accidents, per its internal guidelines; when the Program conducted any telephone or on-scene investigation; or how long the Program took to complete its entire investigation, from initial response to determining cause, because the Program has not tracked the dates or times of any of these activities.

  Although the Program does not track the timeliness of its investigations, Program management and staff, staff from a local fire department, and an operator's staff we interviewed told us that some investigations were ongoing for many months to more than 1 year. Based on available Program data, 15 of the 219 investigations that began between May 2021 and December 2022, had not been completed as of December 31, 2022. For these 15 investigations, the data showed that they had been ongoing for up to 478 days from the date that the operator reported the accident through December 31, 2022, or an average of 57 days that investigations were ongoing.

  Anecdotally, the Program's on-scene gas pipeline accident investigation that we observed as part of our audit did not appear sufficiently timely in order to review the on-scene evidence of an accident, minimize recurrence, or minimize the effects of the safety accident on the local residents involved. On December 20, 2022, we observed the investigation of an accident involving a home explosion in Aurora, Colorado, resulting in the evacuation of the home and surrounding residents, and property damage of at least $50,000, but no injuries requiring hospitalization. We identified the following issues:

  - The explosion occurred on November 16, 2022, but the Program's on-scene investigation did not begin until December 20, or 34 days after the accident. According to the Program management and staff, operator staff and representatives, and fire department staff who were on the scene, it is not uncommon for the on-scene investigation to take place weeks or months after the accident. Operator staff told us that they expedited scheduling this particular investigation with the Program because the explosion occurred around the holidays.

- The property owner, who told us that they were in the home at the time of the explosion, could not live in the home until it was repaired, and was living in a hotel because they had to wait for the investigation to be completed and the cause identified in order for insurance to approve the costs to repair the home. The owner also said that, due to the operator shutting off the gas line for an extended period and having no heat in the home while awaiting the on-scene investigation, the home's water pipes burst, causing additional home damage.

- A nearby neighborhood resident told us they had been evacuated due to the explosion, and the operator had shut off the gas to their home, so they were also staying in a hotel until the investigation could be completed and the gas turned back on.

- The operator staff on the scene told us that they were aware of another accident from the prior year for which the on-scene investigation had not yet begun due to the difficulty of coordinating schedules of an excavator for the site, the operator's investigators and lawyers, and the Program management and staff.

According to Program management, it does not consider the above information on the potential impacts to property owners as relevant to the Program. As a result, the Program has not taken steps to ensure timely investigations to help mitigate such impacts. When the Program does not track the timeliness of its investigations, management cannot ensure that investigators are responding to accidents timely and effectively. In addition, when the Program does not ensure that its on-scene investigations are timely, the evidence needed to determine the cause of the accident can degrade, making it difficult for the Program to make this determination, and ensure there is sufficient evidence to hold the operator accountable for any noncompliance related to the accident, when appropriate. Furthermore, when investigations are untimely, the property owner may not have access to their property and may not have a resolution of the cause that they would need for insurance purposes, as occurred with explosion in Aurora, Colorado. When gas pipeline safety accidents occur in urban areas, surrounding businesses and property owners may be displaced and unable to continue normal operations until the investigation is completed. For example, in June 2022, the accident that resulted in a gas outage in Eaton, Colorado, affected businesses because they did not have hot water and were not able to operate gas-powered appliances, such as restaurant stoves and ovens, during the 4-day outage.

Why did these problems occur?

The problems that we identified related to operators' reporting of and the Program's investigations of accidents, occurred for the following reasons:

- **The Program did not maintain complete investigation records and operator reports prior to May 2021.** Program management told us that it did not have operators' reports of accidents or documentation of each related investigation for Calendar Years 2017 through April 2021 because the records may have been deleted or were not originally maintained by the Program. If such records had existed, it is unclear why they would have been deleted in violation of PHMSA requirements.

- **The Program lacks procedures and tools to consistently track key information on accidents and investigations.** When the Program implemented a process to begin tracking accident investigations in May 2021, it did not implement guidance or procedures for staff to follow when recording the details of the investigations to ensure complete information is tracked consistently. Program management reported to us that it believes its records of reported accidents and investigations were incomplete or missing because the records may have been eliminated based on the judgment of the Program investigators, their conversations with the operator, and/or observations of the accident if they went on site. Management also stated that it may have eliminated records if the accident was resolved quickly or based on how it was resolved, or its staff may have reviewed some of the accident reports that we identified to check if the accidents related to gas pipeline safety, but did not document these reviews. Overall, the Program lacks processes to ensure that its staff maintain records of all reported accidents, and evidence to support that the Program has reviewed/investigated reported accidents timely. Additionally, the database used to track investigation information does not contain fields to record the dates when the Program first responds to the accident, begins the investigation, or concludes the investigation, which the Program would need to ensure that it responds within 72 hours of notification and conducts a sufficiently timely investigation, as required.

- **The Program does not take sufficient steps to hold operators accountable when they fail to report accidents.** The Program has not implemented sufficient processes to monitor the accidents that operators report to NRC, or monitor news media reports for accidents that occurred within the Program's jurisdiction, to identify the operators that have not reported to the Program and take enforcement action against them. In addition, the Program lacks guidance on any compliance actions that should be issued to operators if they fail to meet required reporting timelines, and does not typically penalize operators when they did not report as required. The Program has assessed only one penalty to an operator for failing to report to the Program an accident that occurred in Eaton, Colorado. Specifically, the Program assessed a $50,000 penalty on the operator in June 2022 after the operator did not report an accident that resulted in the town not having gas for 4 days; in December 2022, the Program recommended, and the Commissioners approved, for this penalty to be reduced to $5,000, which was the amount that the PUC collected from the operator.

- **The Program lacks controls related to investigation timeliness.** According to Program management and staff, investigations can be delayed because the on-scene accident investigation takes place when it is coordinated and scheduled by the operator. Program staff told us that it allows operators to direct the timeline for the investigation because the operator is responsible for organizing the resources, such as the backhoe or other equipment, which are typically needed to excavate the pipeline in order to conduct the investigation. The Program has not developed guidance or a process for ensuring staff complete investigations within reasonable timeframes, or otherwise document why investigations cannot be timely, to help ensure the Program is able to review on-scene evidence of the accident when it is available and before it degrades. For example, the Program has not set expectations, such as in regulations, for operators to work with the Program to allow a timely on-scene investigation, such as within 1 week of the accident, or given Program staff guidance on working with operators to ensure the investigation is timely. Written guidance could include general timeframes for how quickly operators should make the accident site available for a Program on-scene inspection, how long the Program should take to conduct an investigation and determine the accident cause, and requirements for documenting any exceptions to meeting the set timeframes. The Program also lacks a process to monitor the timeliness of its investigations to help ensure that conclusions are based on reliable evidence and that further damage is prevented, given that the Program has not begun tracking when it initially responds to accidents, begins the investigation, or concludes the investigation.

- **The Program has not implemented necessary changes to address past PHMSA findings related to investigations.** In 2020, PHMSA found that the Program did not consistently comply with federal requirements for investigations of accidents. PHMSA's annual evaluation for 2020 found that the Program was "not maintaining adequate records, not obtaining sufficient information to determine facts when on-site investigations are not made, not documenting on-site observations and contributing factors, and not initiating a compliance action for probable violations identified [in investigations]" [PHMSA 2020 evaluation]. Although the Program implemented a process to track information on reported accidents and related investigations, in May 2021, the Program has not taken sufficient steps to fully address this federal finding.

- **Lack of Program awareness of some PHMSA guidance for state programs.** Program management and staff we interviewed did not appear to be sufficiently aware of all relevant PHMSA Guidance related to accidents and investigations. For example, management told us it only investigates accidents that result in death, injury requiring hospitalization, and/or property damage of $122,000 or more, as federal regulations require. However, Program management did not appear to be aware of PHMSA Guidelines that have been in place since 2018 that require state gas pipeline safety programs to conduct, at a minimum, a telephonic investigation of all gas-related accidents that are reported to NRC, regardless of jurisdiction, casualties, or property damage to assess the extent to which the accident related to the Program's regulatory authority and needed an investigation. As such, the Program has not implemented practices to fully comply with the PHMSA Guidelines. Further, although the Program's internal guidelines require the Program to investigate accidents resulting in property damage of $50,000 or more, according to management, in practice, the Program does not follow its internal guidelines in this area and believes its guidelines need to be updated. Thus, the Program has not implemented processes to ensure that it complies with all relevant requirements for investigations. The Program also does not provide its staff annual training updates on the Guidelines, which PHMSA updates annually, to ensure staff who conduct investigations for the Program are aware of and following requirements for state programs.

Recommendation 5

The management and staff of the Public Utilities Commission should work with the Department of Regulatory Agencies to improve the Gas Pipeline Safety Program's (Program) awareness and investigation of gas pipeline-related accidents, including incidents and events, by:

A. Maintaining complete Program records of operator reporting of accidents, and of Program investigations, in accordance with federal record retention requirements for the Program.

B. Developing and implementing Program processes to regularly monitor and track gas pipeline safety accident information from the National Response Center (NRC), and to review potential gas pipeline safety accidents reported by the Colorado news media, to identify accidents that have not been reported to the Program but that require Program investigation.

C. Developing and implementing a process to follow up with operators that do not report accidents to the Program as required, and to initiate compliance action for not reporting, as appropriate.

D. Developing and implementing written guidance or procedures for Program staff to follow when recording investigations to ensure complete information is tracked consistently. This should include tracking complete information in investigation records, such as on the accident cause and location to the extent that it is known, and tracking the date and time of the Program's response, the date and details of any on-scene investigation or the applicable reasoning for no on-scene investigation, and the date the investigation is completed.

E. Developing and implementing written Program guidance and/or regulations to promote timely investigations. This should include, but not be limited to, implementing expectations in regulations for operators to work with the Program to help ensure timely investigations, and guidance for Program staff to complete investigations within general timeframes or otherwise document the reasoning for investigations that do not meet timeframes.

F. Developing and implementing a Program process to monitor the timeliness of investigations to help ensure investigations are timely in ensuring accident sites are safe for the public and the impact to property owners is minimized, and in identifying probable cause, minimizing the possibility of recurrence, and instituting enforcement actions for operator noncompliance identified through investigations.

G. Implementing annual training on the updates to federal guidance for Program management and staff with responsibilities related to monitoring operator reporting on incidents and events, and for those with responsibilities related to investigations.

H. Implementing any additional changes to Program processes that are needed to ensure that the Program has fully addressed the federal Program evaluation finding related to documenting investigations, on-site observations, and initiating compliance action for probable violations identified in investigations.

Response

Public Utilities Commission and Department of Regulatory Agencies

A. Agree
Implementation Date: December 2023

The PUC will work with the Department to improve the Program awareness and investigation of gas pipeline-related accidents including incidents and events. The PUC will update its records retention policy in the State Agency's written Program Guidelines to require retention of records of operator reporting of accidents and Program investigations in accordance with federal record retention requirements for the Program.

B. Partially Agree
Implementation Date: March 2024

The PUC will update the State Agency's written Program Guidelines to include and implement processes to document the Program's decision path to respond to a report, whether in person, via remote communications (such as a phone call), or to determine if the Program has authority to respond to the report. The process will include details about how the Program monitors and tracks information from the National Response Center and Pipeline Emergency Reporting line, consistent with applicable federal and state statutes, rules, and guidelines.

A process to address information reported by the Colorado news media, which is identified as the major news outlets and sources that provide information to news outlet subscription services, will be developed and implemented to review and identify news information for potential unreported gas pipeline safety issues.

The PUC will track non-jurisdictional NRC gas related incidents to show the Program has identified the reported event is non-jurisdictional, but will not make telephonic investigations on non-jurisdictional NRC incidents that are not under 60105 and 60106 requirements confirmed by PHMSA in its 5/16/2023 email to the Program, as quoted below:

> [U]nder your 60105 certification you are only allowed to use your authority to enforce the PHMSA regulations found in 49 CFR 192 – 199 dependent on the states certification status. That means you can only exercise the authority over those operators that fall directly under your jurisdiction. Some examples of those that don't might be the operator of a hazardous liquids pipeline, interstate transmission pipeline or a gathering line operator who falls outside of the regulations.
> You will have a list of operators that fall under your jurisdiction that is reported on your progress report. It should be reviewed and updated each year.

Auditor's Addendum

As noted in the audit finding, PHMSA Guidelines, state regulations, and Program internal guidelines require the Program to review each accident (i.e., incidents and events) related to intrastate gas pipelines, facilities, and underground storage that is significant and/or that is reported to the NRC or the Program, to determine if the accident is within the Program's jurisdiction, and therefore, requires an investigation. Specifically, PHMSA Guidelines that have been in place since 2018 require state gas pipeline safety programs to conduct, at a minimum, a telephonic investigation of all gas-related accidents that are reported to NRC, regardless of jurisdiction, casualties, or property damage to assess the extent to which an accident is related to the Program's regulatory authority and should be investigated. The audit found that the Program does not currently have sufficient processes to monitor and track gas pipeline accidents that Program-regulated operators report to the NRC. These processes are needed in order for the Program to identify gas pipeline safety accidents that fall within the Program's jurisdiction but that operators do not report.

C. Agree
Implementation Date: March 2024

The PUC will update the State Agency's written Program Guidelines to include a process to follow up with operators that do not report incidents and events to the Program as required, including initiation of a compliance action for not reporting, consistent with applicable federal and state statutes, rules and guidelines.

D. Agree
Implementation Date: June 2024

The PUC will update the State agency's written Program Guidelines to include a process for Program staff to follow when recording investigations in the new OnBase application. Information to be included in the application will include the accident cause and location, the date and time of the Program's response, the date and details of any on-scene investigation, and the date the investigation is completed. While implementation will begin under existing systems, full implementation will likely not be able to be completed until completion of systems development by OIT.

E. Agree
Implementation Date: June 2024

The PUC will work with the Department to improve Program awareness and investigation of accidents/incidents/events. The PUC will update the State agency's written Program Guideline to implement processes for the Program and management to monitor and ensure the timelines of investigations are met. Information will be communicated to the operators including regulatory obligations of operators to respond and cooperate with Program inquiries and coordinated with scheduling timeframes for inspections. The Program will maintain records of operator reporting and of program investigations.

OIT is currently developing an application for the Program utilizing Hyland's OnBase platform. The PUC will work with OIT to ensure processes implemented are documented accordingly in that new system. While implementation will begin under existing systems, full implementation will likely not be able to be completed until completion of systems development by OIT.

F. Agree
Implementation Date: June 2024

The PUC will update the State agency's written Program Guideline to implement processes for the Program and management to monitor and ensure the timelines of investigations to help ensure investigations are timely in ensuring accident sites are safe for the public and the impact to property owners is minimized, and in identifying probable cause, minimizing the possibility of recurrence, and instituting enforcement actions for operator noncompliance identified through investigations. Information will include regulatory obligations of operators to respond and cooperate with Program inquiries and coordinated with scheduling timeframes for inspections.

OIT is currently developing an application for the Program utilizing Hyland's OnBase platform. The PUC will work with OIT to ensure processes implemented are documented accordingly in that new system. While implementation will begin under existing systems, full implementation will likely not be able to be completed until completion of systems development by OIT.

G. Agree
Implementation Date: March 2024

The PUC will implement a training plan that will provide for training on the updates to federal guidance, for Program management and staff with responsibilities related to monitoring operator reporting on incidents and events, and for those with responsibilities related to investigations.

H. Agree
Implementation Date: June 2024

The PUC will implement processes that are needed to ensure that the Program fully addresses past federal Program evaluation findings.

Finding 6—Inspector Training and Supervision

PHMSA provides a variety of required and optional trainings for state entities that have pipeline safety programs and that conduct federally funded inspections. Inspectors either need to complete PHMSA training for the types of inspections they conduct, or management of state pipeline safety programs should evaluate the inspectors' knowledge and skills to ensure they are qualified to conduct the inspections before completing required training. PHMSA offers both in-person and online courses on subjects such as conducting each type of pipeline safety inspection (e.g., integrity management, or operator qualifications), following up on operator compliance, and conducting investigations of accidents. To complete training for some types of inspections, inspectors must attend one in-person course, whereas for other types of inspections, they must attend multiple in-person courses that can take several days to complete. For example, basic inspector training includes six in-person courses that are provided out-of-state over multiple days. In addition, Program management told us that newer inspectors receive on-the-job training and supervision until they are able to complete the classroom training required by PHMSA. PHMSA maintains a training portal that the Program can access to register for trainings and to review the courses that Program staff complete.

The Program uses the federal Inspection Assistant (IA) system to conduct inspections and to track whether an inspection was reviewed by a supervisor or a trained or qualified inspector. The system has a "supervisor" box that someone can check to show that the inspection record was reviewed. IA allows multiple individuals to check this "supervisor" box for an inspection record, and documents each person that signs off as "supervisor" on that inspection.

What was the purpose of the audit work and what work was performed?

The purpose of our audit work was to assess whether Program inspectors had completed the required trainings to conduct inspections during Calendar Years 2020 through 2022 and, if an inspector had not completed the required trainings, whether (1) their knowledge and skills had been evaluated before they conducted inspections, and (2) they received direct and timely supervision when completing inspections. We reviewed Program documentation and management's written updates on the training courses that inspectors had completed as of March 2023, and compared it to the Program's internal state inspection data and records (internal records) from various systems and databases, showing the types and dates of inspections, and the inspectors who conducted them. We requested the Program's documentation showing its evaluation of inspector qualifications, knowledge, and skills for the types of inspections reviewed, and Program management provided the federal grant application that it submitted to PHMSA, which listed the Program staff employed as of October 2021 and their job titles. We also reviewed inspection records in IA to determine the extent to which Program supervisors signed off on completed inspections. Finally, we interviewed Program management and staff to understand training and supervision processes.

How were the results of the audit work measured?

We measured the Program's adherence to federal law and PHMSA Guidelines for the Program, which require inspectors to be trained and qualified to conduct inspections. Specifically:

- **Federal training is mandatory for state employees who carry out pipeline safety inspections.** Under federal law, PHMSA develops guidelines for inspector qualifications and for training programs that "shall be mandatory for…State employees who conduct federally funded compliance reviews, inspections, or investigations" (*2012 Hazardous Materials Transportation Safety Improvement Act*, 49 USC 5101-33008). This federal training is mandatory for state programs unless a state chooses to develop and provide in-house training that is equivalent to the federal training, which Colorado's Program does not do.

- **Inspectors must complete required federal training prior to leading an inspection.** PHMSA allows inspectors up to 5 years to complete all required training courses for the various inspection types, but inspectors cannot independently conduct a type of inspection for which they have not completed training. Specifically, according to PHMSA Guidelines, lead inspectors must successfully complete the required Training and Qualifications (TQ) courses prior to (1) leading standard inspections; (2) conducting inspections of natural gas, operator qualifications, integrity management protection, damage prevention, operator training, and construction; and (3) conducting compliance follow-up [PHMSA Guidelines 2018, 4.6; and 2021, 4.3.1]. The Guidelines also state that an inspector may lead an inspection only if they meet certain minimum qualifications, and program managers or supervisors who perform inspections must meet these same training requirements. As long as one member of the inspection team conducting the inspection meets the requirements of Lead Inspector, PHMSA considers the Lead Inspector requirements to have been met. PHMSA Guidelines do not specifically define "Lead Inspector," but according to Program management, a lead inspector is someone who conducts an inspection independently. As such, this audit considered someone to be leading an inspection if the Program records showed that the individual conducted the inspection independently.

  The Program's internal guidelines also emphasize the need for inspectors to complete training, and state that, "Program certification relies on professionally trained inspectors to lead gas pipeline safety inspections...Every [Program] team member must have Basic Gas Inspector training." Program certification refers to Colorado's authority to administer the Program to regulate intrastate gas pipelines on behalf of the federal government.

- **Inspector knowledge and skills may substitute for training, as long as the inspector is not conducting activities independently and there is a documented evaluation of their qualifications.** PHMSA requires that, "Each State agency should be staffed with qualified personnel who are experienced in pipeline safety operations and/or have an educational background in engineering or related technical fields. Personnel with less than these minimum qualifications may be hired provided the State agency takes **immediate** steps to provide training opportunities to meet the required level of competency. Staff should not be permitted to conduct **independent** activities until it is determined that they have demonstrated the ability and proficiency to perform their duties satisfactorily" (**emphasis added**) [PHMSA Guidelines 2018 and 2021, 4.6]. According to the PHMSA Guidelines, the Program Manager may allow for an inspector to lead an inspection prior to completing the required PHMSA courses as long as the manager evaluates the inspector's knowledge and skills based on the training requirements, and the manager uses the appropriate evaluation form to document the evaluation and the criteria, factors, and steps that resulted in qualifying a state inspector as a lead inspector for each inspection activity [PHMSA Guidelines 2021, 4.3.1].

- **Inspectors should be supervised if they conduct inspections for which they are not trained.** According to Program management, inspectors who have not completed the required training for a particular inspection type, can work on that type of inspection as long as they are supervised by someone who has the required experience or training, and they have prior qualifications and experience with gas pipeline safety. Program management told us that the evidence of a supervisor's review of an inspection is the supervisor's sign off in IA, which allows someone to check a box that documents their name and the date they reviewed the inspection record. PHMSA has established a hierarchy of roles and sign offs in IA—Assignee, Observer, Inspector, Lead, Supervisor, and Director—with different responsibilities at various levels. For example, a supervisor has the ability to modify inspection records in the system. PHMSA defines supervisor as an individual in a State Agency supervising pipeline safety inspectors/investigators [PHMSA Guidelines, Glossary]. The general purpose of a supervisor sign-off is to document that a supervisor or trained/qualified staff member oversaw the inspection to help ensure that it met federal requirements. As a best practice, this supervisory sign-off should be timely.

What problems did the audit work identify?

Overall, we found that Program inspectors were not always trained on the types of inspections that they conducted independently; management did not document the inspectors' knowledge and skills; and the Program did not have evidence that these inspectors received appropriate, consistent supervision. Specifically, we found:

- **Most inspectors lacked required training for some types of inspections that they conducted independently.** Altogether, the Program's internal state inspection records showed that 13 of the 15 inspectors independently conducted a combined total of 545 inspection activities of various operator units in Calendar Years 2020 through 2022, before the inspectors completed the required training for those specific types of inspections, and without evidence of the required supervision. Exhibit 2.13 shows the numbers, types, and hours of inspections that each of the 13 inspectors conducted prior to completing the relevant training.

Exhibit 2.13
Inspections by Inspectors Who Had Not Completed Required Training
Calendar Years 2020 through 2022

	Number of Inspections by Inspector, by Type						
Program Inspector	**Operator Integrity Management**	**Standard Inspection**	**Incident/ Event**	**Compliance Follow-up**	**Operator Qualifications**	**Total Inspections Per Inspector**	**Inspection Hours Per Inspector**
A	6	1	1			8	56
B	9					9	63
C	6	11	7	30		54	184
D	2					2	16
E	2	8	7		1	18	95
F			4			4	14
G		24			1	25	80
H	2					2	4
I	56					56	231
J	6	42		8	1	57	244
K	63	1	6		3	73	536
L	81	7	23		2	113	802
M	3	118	1		2	124	626
Totals	**236**	**212**	**49**	**38**	**10**	**545**	**2,951**

Source: Office of the State Auditor's analysis of Program training and inspection documentation and data.

As shown in Exhibit 2.13, the 13 inspectors logged a total of 2,951 inspection hours conducting inspections for which they had not completed required training, which was about 18 percent of all 15,969 inspection hours that the Program reported to PHMSA for these years. None of the 13 inspectors had completed the full training courses required for inspection types before they conducted the inspections in Calendar Years 2020 through 2022. As such, the remainder of this finding refers to these 13 inspectors as "untrained inspectors."

In March 2023, the Program provided training records that showed that seven of the 13 inspectors had just completed some training courses, and some of the inspectors were scheduled to attend training or were on a waitlist for training later in Calendar Year 2023. For example, as of March 2023, one inspector had completed the training for operator qualifications, and the Program Manager was scheduled to attend two trainings required for standard inspections.

- **The Program lacked evidence that untrained inspectors were supervised.** For 176 of the 545 (32 percent) inspections, we could not determine whether the 11 untrained inspectors who conducted them had been supervised because the Program did not have complete documentation. Specifically, the Program's detailed internal state records showed that the inspections occurred, but did not indicate that supervision had occurred. The Program did not record these inspections in the federal IA system, which the Program uses to track supervisory review of inspections; therefore, there was no record of whether or not supervision occurred.

For most of the remaining 369 of the 545 inspections (68 percent), the inspectors did not appear to have been supervised by qualified and/or trained staff. The records for these inspections were recorded and grouped in IA into 106 records based on the area that the inspectors had inspected over the course of the calendar year. We reviewed these 106 IA-grouped records and found:

- **No evidence of supervision for 85 percent of inspection records.** First, for 80 percent (85 of 106 IA records), the Program's administrative project coordinator signed off on the inspection records as the "supervisor," although this administrator was not a supervisor, had not received any inspection training, and did not have inspection experience. According to Program management, this administrator had not supervised the inspectors; rather, the administrator was listed as the supervisor on the inspection records provided to PHMSA because the administrator had checked that the inspectors completed the fields on the inspection template in IA. There was no other documentation in IA or the Program's detailed state records to show that a qualified or trained individual had supervised these inspections. Second, for another 5 percent of the inspection records (5 of 106 IA records), no supervisor was listed in IA.

- **The supervisor was untrained for 9 percent of inspection records.** First, for 8 percent (9 of 106 IA records), the Program Manager had signed off as completing a supervisory review of the inspections, but this individual had also not completed the specific trainings required for the types of inspections conducted. In addition, the Program did not have any documentation to show when the Program Manager signed off on these inspections, such as at the time the untrained inspector conducted the inspection or at some point after the inspection. As a result, it is unclear whether this supervision was timely. Second, one additional record (about 1 percent) showed that a new inspector had signed off as completing their own supervisory review.

  According to PUC management, the Program Manager is working on completing the required trainings, but they also stated that they do not believe that the person who supervises untrained inspectors or who conducts supervisory review of inspection records would need to complete applicable required training. However, as discussed previously, PHMSA Guidelines indicate that program managers or supervisors who perform inspections must meet the same training requirements as inspectors, and it would be best practice for a supervisor of an untrained inspector to complete the necessary training for the types of inspections that they supervise.

- **Supervision occurred, but it was unclear if it was timely for 6 percent of inspection records.** For 6 percent (6 of 106 IA records), the inspection records showed that two Program supervisors who were trained on the types of inspections conducted, had signed off as having completed the supervisory review. However, the Program did not have documentation to show when that supervisory review occurred and whether it was timely.

Program management agreed that it had inadequate documentation of supervision that may have occurred, but stated that the untrained inspectors could have contacted supervisors with any questions, if needed.

- **Management lacked documentation to support that untrained inspectors' had knowledge and skills to independently inspect without training.** The Program did not have documentation showing management's required evaluation of the knowledge and skills of the 13 inspectors who had not completed the required training for the types of inspections that they conducted independently. The Program's documentation only listed staff names and job titles, which management believed was sufficient to show the inspectors' prior experience because the Program typically hires individuals from the gas pipeline industry. However, in March 2023, in response to the audit team's questions about inspector training and qualifications, PUC and Program management told us that they had to ask the inspectors about their prior work experience because management could not recall this information, and the information was not documented by the Program.

  In accordance with PHMSA Guidelines, a documented evaluation of the inspectors' knowledge and skills based on the training requirements could have qualified the inspectors to conduct independent inspections without the training if management had conducted this evaluation. Furthermore, as we explain in our *Inspector Conflicts of Interest* Finding, according to Program management, one of the 13 untrained inspectors had a prior role in training, but not in pipeline safety. Had management conducted an evaluation of this inspector's knowledge and skills in accordance with PHMSA requirements, they might have determined that this inspector, at a minimum, did not have sufficient experience to independently conduct inspections without training.

Why did these problems occur?

The problems we identified related to inspectors conducting inspections prior to completing required training and without evidence of supervision occurred for the following reasons:

- **The Program's practices in this area do not align with federal requirements.** According to Program management, during the years reviewed by this audit, the Program has not had a sufficient number of qualified and trained inspectors to conduct inspections in accordance with federal requirements. As a result, the Program has had to assign inspections to staff who have not completed required training for the type of inspections they conducted, and there has been a lack of trained staff who can supervise. Program management also stated that they believe that an inspector's prior work experience is sufficient to qualify them to inspect independently—without required federal training and direct supervision—and that ad hoc and informal on-the-job training sufficiently trains inspectors before they complete federal training. Program management and staff indicated that inspectors are not assigned to inspections based on the federal training that they have completed. However, the practice of having inspectors conduct inspections independently before completing the required federal trainings, and without a documented evaluation of the inspectors' qualifications prior to inspections, does not align with federal requirements.

- **The Program has not implemented adequate processes to ensure supervision or to document supervision.** This audit found that the Program does not assign a trained/qualified inspector or supervisor the responsibility of ensuring that each inspection is adequate and complies with federal requirements. Instead, according to Program management, if the untrained inspectors had questions while they were inspecting, then trained/qualified inspectors or supervisors were available for questions. Specifically, Program management told us that "All of our inspectors have demonstrated to the senior staff members that they have the ability and proficiency to perform these inspection duties satisfactorily and have been allowed to conduct certain inspections independently, always with a supervisor available by phone to discuss issues…and are able to contact a supervisor for questions or discussion." Program management also told us that for remote inspections it may have one trained/qualified inspector "jumping in and out of Zoom [inspections] as needed." However, making trained staff available for questions, and joining remote meetings as needed, is not active supervision or oversight, and the Program had no documentation to show that this oversight or supervision occurred.

  In addition, Program management told us that it has allowed an administrative project coordinator—who is not a supervisor—to sign-off on federal inspection records in IA on most of the inspections conducted by untrained inspectors because the administrator was assigned to proof-read that all fields on the inspection forms had been filled in prior to the Program submitting its grant application to PHMSA. Although Program management acknowledged that only trained/qualified staff should provide inspection supervision, management indicated that it did not believe that it was a problem for a non-supervisor to sign-off as "supervisor" on an inspection record; management explained that it prefers to use the "supervisor" field in IA to indicate that someone reviewed the inspection to make sure the documentation was complete, not to determine if the inspection was completed per requirements. However, the federal intent of the hierarchy of sign offs in IA, and the intent of the supervisor sign off, are not met when a non-supervisor signs off as a "supervisor" in the federal system. The practice of allowing a non-supervisor to sign-off as "supervisor" for inspections gives the false appearance that supervision by a Program supervisor or a trained/qualified inspector has occurred when it has not. Additionally, someone designated as a supervisor in IA has the ability to modify inspection records, which may not be appropriate for a non-supervisor who is an administrative project coordinator.

- **The Program has not implemented processes to document management's evaluation of inspector knowledge and skills.** According to Program management, it believes that it hires individuals who have the qualifications, experience, and skills to conduct inspections without having completed the required trainings, based on the information that new hires submit on their resume and job application, and based on an undocumented evaluation that has "determined they could handle inspections before sitting through the TQ class." However, the Program does not have a process to document the evaluation of each inspector's knowledge and skills to conduct inspections independently, as required by PHMSA.

Why do these problems matter?

When Program inspectors are not trained on the types of inspections that they conduct independently, inspectors' knowledge and skills are not documented, and there is a lack of evidence the inspectors are supervised, the following risks can occur:

- **Risk of inconsistent inspections, or of safety issues not being identified timely.** The lack of uniform training and supervision for investigators can lead to inconsistent inspection reviews because untrained and unsupervised investigators may apply different interpretations of the requirements for pipelines and their operators. There is also a risk that safety hazards or noncompliance are not identified or reported, which can increase the risk to public safety. For example, there is a possibility that an untrained inspector who is independently inspecting an operator without assistance or supervision, may misidentify an unburied, unprotected pipeline as a safety concern (i.e., something that may become a violation) rather than a probable violation (i.e., something that requires compliance action).

  Additionally, lack of training and supervision for inspectors can increase the risk of biased inspections. Three of the inspectors who conducted inspections before completing the training for those inspections—Inspectors G, K, and M shown in Exhibit 2.13—had conflicts of interest for some of their inspections because they were inspecting their immediate former employer. There is a risk that these prior relationships could result in an inspector making conscious or unconscious biased decisions, such as reporting incomplete information so that their former employer appears compliant when they are not or reporting inspection results unfairly by understating their former employer's compliance with regulations. This risk is also discussed in our *Inspector Conflicts of Interest* Finding.

- **Program noncompliance with PHMSA requirements can result in decreased federal funding for the State.** When untrained inspectors independently conduct inspections for which they have not been trained, and there is no evidence that all untrained inspectors are supervised, it may affect the quality of inspections or inspection documentation, which could result in PHMSA decreasing the amount of federal funding the State receives. PHMSA reimburses the State for Program expenses based on available federal funding and the Program's adherence to federal requirements. In PHMSA's annual evaluations of the Program's performance for Calendar Years 2020 and 2021, PHMSA found that inspectors were not answering all inspection checklist questions, not issuing compliance actions for all probable violations, and not maintaining adequate records, which indicates that the lack of training and supervision may have affected the Program's performance. In these years, PHMSA documented that it scored the

Program lower on the performance evaluations and reduced the Program's federal reimbursement. For 2020, PHMSA reimbursed Colorado's Program for 65 percent of its expenses; for 2021, the Program was reimbursed 64 percent of its expenses. According to PHMSA, the Program is eligible to receive a maximum reimbursement of up to 80 percent of expenses.

Recommendation 6

The management and staff of the Public Utilities Commission should work with the Department of Regulatory Agencies to ensure that the Gas Pipeline Safety Program (Program) complies with federal requirements for inspector training and supervision of inspections, by:

A. Developing and implementing processes to ensure that inspectors either have completed required federal training for the types of inspections that they conduct independently or lead, or that inspectors receive active supervision or supervisory review by a supervisor or inspector who has completed the required training for the type of inspection being conducted or who is documented as being qualified to supervise that type of inspection.

B. Developing and implementing a process for trained/qualified staff to conduct supervisory review of inspection records to ensure that inspections are conducted in line with inspection requirements, and for documenting evidence of this supervisory review in the federal system and in the internal state Program records. This should include ensuring that a trained/qualified staff signs off as "supervisor" in the federal system.

C. Developing and implementing a process to document Program management's evaluation of inspector knowledge and skills to ensure that they are qualified for the types of inspections before being assigned to conduct them.

Response

Public Utilities Commission and Department of Regulatory Agencies

A. Agree
Implementation Date: March 2024

The PUC will work with the Department to ensure that the Program complies with federal requirements for inspector training, and supervision of inspections. The PUC will develop and implement processes to ensure documentation that those that conduct inspections independently or lead inspectors have either completed required federal training for the types of inspections they lead or direct supervision by a lead inspector who has completed the required training for the type of inspection being conducted, consistent with applicable federal and state guidelines.

B. Agree
   Implementation Date: March 2024

   The PUC will update its State Agency written Program Guidelines and will develop and implement a process for trained/qualified staff to conduct supervisory review of inspection records to ensure that inspections are conducted in line with inspection requirements, and for documenting evidence of this supervisory review in the federal system and in the internal state Program records. This will include ensuring that a trained/qualified staff signs off as supervisor in the federal system.

C. Agree
   Implementation Date: March 2024

   The PUC will update the State Agency's written Program Guidelines to implement a process to document Program management's evaluation of inspector knowledge and skills to ensure that they are qualified for the types of inspections before being assigned to conduct them. The job evaluation procedure developed will allow the Program Manager to consider the needs of the state agency, size of inspection staff and other factors in deciding whether an inspector is qualified to be a lead inspector on a Standard inspection prior to completion of the full required Training and Qualifications courses learning path.

Finding 7—Federal Reporting

The Program reports key information on its operations to PHMSA as part of the Program's certification to administer this federal-state program on behalf of the federal government [49 USC 60105]. PHMSA relies on the accuracy of the Program's reporting to make decisions on funding and assess the Program's oversight of pipeline safety problems. Examples of information that the Program reports to PHMSA annually include the number of inspection days completed, the compliance actions taken to enforce operator compliance with safety requirements, and gas pipeline safety accidents in the state. The Program maintains information that it needs to report to PHMSA in detailed internal data and documentation, and records certain information in the federal Inspection Assistant (IA) system.

PHMSA conducts an annual evaluation of each state program, which reviews the information that the Program records in IA and that it reports to PHMSA in its annual grant application and annual progress report. PHMSA then compares the Program information to federal requirements, expected performance metrics set by PHMSA, and the performance of other state pipeline programs. Congress appropriates funding to PHMSA each year for the federal grant program, and PHMSA determines the amount of merit-based grant funding that each state will receive out of the total funds available. PHMSA's determination of how much funding a state program will receive each year is based on the state program's score on the annual evaluation.

What was the purpose of the audit work and what work was performed?

The purpose of the audit work was to assess the accuracy of the Program's reporting to PHMSA. We reviewed the available data and documentation that the PUC and Program were able to provide on Program operations, enforcement, and activities for Calendar Years 2019 through 2022. We performed data reliability testing by comparing this internal data and documentation to the information that the Program reported to PHMSA in IA and on grant applications and progress reports in Calendar Years 2019 through 2022. We also interviewed Program management on its processes to track and report Program information to PHMSA.

How were the results of the audit work measured, what problems were identified, and why do they matter?

Overall, we found that the Program misreported information to PHMSA for many areas of Program operations, and across multiple years. Specifically, we found that the Program has not reported accurate or complete information to PHMSA in areas such as inspections, enforcement, and accidents. As part of federal grant requirements, the Program must report accurate and complete information to PHMSA on the Program's annual grant application and progress report [49 USC

60105(c), and PHMSA Guidelines 2018 through 2022, 2.7 and 9], and the application and progress report should be "up to date" so that PHMSA is able to use the information when conducting its annual evaluation of the Program [PHMSA Grant Application Form]. The Program should put inspection records in IA so that PHMSA can use the information to evaluate Program performance, and the Program should have "verification [that] all required data points are uploaded or entered into the proper state and federal [databases] within a reasonable time" [PHMSA Guidelines 2018 through 2022, 5.1].

Exhibit 2.14 summarizes the federal reporting requirements, and the discrepancies that we identified when we compared the Program's data and documentation to the information that the Program reported to PHMSA in annual grant applications and progress reports.

Exhibit 2.14
Program's Underreporting and Overreporting of Key Information to PHMSA
Calendar Years 2019 through 2022

Program Underreported Colorado's Pipeline Safety Accidents	
Reporting Requirement: As part of annual grant progress reports, the Program must report all accidents/incidents investigated by or reported to the Program, along with a summary of the investigation of the cause and circumstances [49 USC 60105].	
Years When Information Misreported	2021[1] and 2022
What Did Program Report to PHMSA?	5 accidents reported in progress reports. The Program also reported that it maintained records of all accidents.
What Did Program Records Show?	219[2] accidents reported directly to the Program. The Program also did not maintain records of all accidents prior to May 2021.
Program Overreported Inspection Days	
Reporting Requirement: As part of annual grant progress reports, the Program must report the total number of inspection days spent conducting inspections [PHMSA Guidelines Attachment 2].	
Years When Information Misreported	2019 and 2020
What Did Program Report to PHMSA?	503.85 inspection days reported in 2019 progress report, and 670.8 inspection days reported in 2020 progress report, based on the total hours recorded in the Program's internal inspection records. Program management reported to PHMSA that 1 inspection day equals 8 hours per inspector, per day.
What Did Program Records Show?	Only 445.6 inspection days in 2019 and only 609 inspection days in 2020, based on the total hours recorded divided by 8 hours per inspector, per day. In 2020, for 419 inspections, the Program's inspectors recorded more than 8 hours of work for 1 inspection day, including recording as many as 22.5 hours for 1 day, although the Program reported to PHMSA that 1 day equaled only 8 hours. Program management used the total hours recorded to calculate the number of inspection days, even when staff recorded more than 8 hours, which erroneously increased the reported inspection days and contributed to the overreporting in 2020.
Program Did Not Report All Inspections/Inspection Types Completed	
Reporting Requirement: As part of annual grant progress reports, the Program must report all inspection activity in the state [PHMSA Guidelines Attachment 2]. The Program must also report its performance and what the Program accomplished during the year to contribute towards annual and long-term goals, such as to develop the Program's inspection priorities, improve programmatic activities, and improve data management [PHMSA Guidelines Attachment 10].	
Years When Information Misreported	2022
What Did Program Report to PHMSA?	The Program reported to PHMSA, in progress reports, that inspectors used IA to document all inspection activities in order to help meet the Program's goals.

What Did Program Records Show?	319 inspections were not recorded in IA in 2022, but were listed in the Program's internal data. For example, in IA, the Program did not record all inspections of master meter operators (only 2 of 57 were recorded in 2022), any follow-up inspections for noncompliance, or records of investigations. Some other inspection types, such as standard and integrity management, were inconsistently recorded in IA.
Program Overreported and Underreported the Issued Compliance Actions	
Reporting Requirement: As part of annual grant progress reports, the Program must report all compliance actions taken for the calendar year [PHMSA Guidelines Attachment 5].	
Years When Information Misreported	2021 and 2022
What Did Program Report to PHMSA?	9 compliance actions taken in 2021 and 2 compliance actions taken in 2022, as reported in progress reports. The Program also reported that it maintained records of all compliance actions.
What Did PUC/Program Records Show?	8 compliance actions taken in 2021 and 17 compliance actions taken in 2022, according to all available PUC documentation and data. The Program also did not maintain records of all compliance actions, as it had reported to PHMSA.
Program Overreported Enforcement	
Reporting Requirement: On the annual grant application, the Program certifies that it is enforcing each applicable safety standard [PHMSA Base Grant Application]. Attachment 1 of the grant application "requires a description of all ongoing and planned pipeline safety program activities for which grant reimbursement is requested. This summary must clearly indicate the types of actions to be performed and contain sufficient details to justify the proposed budget." These include "major enforcement cases that are expected to take large amounts of resources" and "Notable program activities to be conducted during upcoming calendar year" [PHMSA Guidelines 2018 through 2022, 9].	
Years When Information Misreported	2019 through 2022
What Did Program Report to PHMSA?	The Program reported in its grant applications that in "2019, the [Program] began…to pursue complaints against persons damaging pipelines that caused a definitive impact to public or environmental safety" and "will continue these efforts in 2022," as "notable program activities to be conducted." Additionally, in 2022, the Program reported in its grant application that pending compliance actions against multiple private master meter operators would be "major enforcement cases that are expected to take large amounts of resources."
What Did Program Records Show/ What Did Program Management Tell Auditors?	The Program had no evidence that it issued compliance actions against persons damaging pipelines for 87 documented instances or for damages that caused "a definitive impact to public or environmental safety" in Calendar Years 2019 through 2022. These instances resulted in one death and $992,000 in property damage. The accident involving a death was caused when one public operator improperly identified the location of a pipeline and the line was subsequently struck and caused an explosion. Additionally, the Program told us that the compliance actions related to private master meter operators were related to recordkeeping, indicating that they were not major enforcement cases, as the Program had reported to PHMSA.
Program Overreported Having Records of Other Program Activities	
Reporting Requirement: As part of annual grant progress reports, the Program must provide PHMSA a list of the key records and reports that the Program maintains to meet federal requirements [PHMSA Guidelines Attachment 6].	
Years When Information Misreported	2020 and 2021
What Did Program Report to PHMSA?	Program reported in the progress reports for these years that it retained information on "notes/handouts concerning Regional Public Awareness/Damage Prevention Programs," and "industry correspondence."
What Did Program Records Show?	The Program reported to the audit team that it did not perform Public Awareness inspections in 2020 and 2021, so records were not available, and the Program was not able to provide documentation of industry correspondence for 2020 and 2021, which contradicts what the Program reported to PHMSA in progress reports.

Program Misreported Who Conducted Inspections	
PHMSA Requirement: Federal training is mandatory for state employees who carry out pipeline safety inspections, [2012 Hazardous Materials Transportation Safety Improvement Act, 49 USC 5101-33008], and inspectors must complete required federal training prior to leading an inspection, or otherwise be supervised by a trained inspector [PHMSA Guidelines 2018 through 2021, 4].	
Years When Information Misreported	2020 through 2022
What Did Program Report to PHMSA?	In IA, the Program reported that trained/qualified inspectors conducted nearly 2,000 inspection activities, or were supervised if they were untrained, across Calendar Years 2019 through 2022. The Program reported that three inspectors who had completed all required training were the lead inspectors for all inspections that year.
What Did Program Records Show?	The Program did not record accurate inspector names in IA for a total of 545 inspection activities in Calendar Years 2020 through 2022; therefore, it inaccurately appeared that trained/qualified inspectors had independently conducted or led these inspections, when internal Program records showed that those who conducted the 545 inspections were untrained. There was also inadequate evidence of supervision in the records.
Program Overreported State Regulation Compliance With Federal Regulations	
Reporting Requirement: As part of annual grant progress reports, the Program must report if state regulations are in compliance with applicable federal requirements [PHMSA Guidelines Attachment 8]. The Program must also certify that it has adopted substantially the same federal regulations in its annual grant application.	
Years When Information Misreported	2019 through 2022
What Did Program Report to PHMSA?	The Program reported in annual grant applications and progress reports for 2019 through 2022, that state regulations complied with all federal regulations, including those requiring penalties ranging from $200,000 to $2 million for operator noncompliance.
What Did Program Records Show?	State regulations have not been updated to reflect federally-required penalties. The state regulations show penalty amounts of $100,000 to $1 million respectively.

Source: Office of the State Auditor's analysis of Program grant applications, progress reports, IA records, and internal Program records for Calendar Years 2019 through 2022.

[1] Program management was unable to locate Program records on accidents prior to May 2021; the Program began tracking accidents in May 2021.

[2] The 219 accidents had been reported directly to the Program and were tracked by the Program. The 219 accidents do not include additional accidents that this audit identified by reviewing the National Response Center's public data and Colorado news media reports, as these accidents had not been tracked by the Program.

PHMSA relies on the accuracy and completeness of the information provided by the Program in order to report gas pipeline safety information to Congress, assess the Program's compliance with federal requirements, and determine the Program's annual federal grant funding [PHMSA Guidelines 2018 through 2022, 9]. When the Program misreports information to PHMSA on inspections, compliance actions, or accidents, the federal agency has incomplete information needed to monitor Program operations to determine if the state complies with federal laws, regulations, guidelines, and requirements for the federal grant. For example, when the Program does not provide PHMSA complete information on all safety accidents, PHMSA may not have the information needed to monitor safety problems in Colorado or to check that the Program investigated all accidents as required.

Further, when PHMSA cannot rely on the information that the Program reports to accurately check that the Program is meeting federal requirements and standards, it may decrease PHMSA's ability to hold the Program accountable. For example, PUC staff reported to the audit team that PHMSA gave the Program a high evaluation score on the recent Calendar Year 2022 performance evaluation compared to prior years. However, based on the results of this audit, the Program misreported information to PHMSA and in IA on accidents/incidents, inspection activities, compliance actions, enforcement efforts, the staff who conducted inspections, and state regulation compliance.

Additionally, based on PHMSA's documentation of its 2021 evaluation of the Program, PHMSA appeared to make incorrect conclusions of the Program's performance due to Program misreporting in IA. For example, PHMSA's evaluation noted that, although certain inspectors were not qualified to conduct the inspections they were assigned to, PHMSA did not deduct points from the Program's score on the evaluation because the Program's IA records listed that a qualified inspector led the inspection. There was no evidence in PHMSA's 2021 evaluation that PHMSA was aware that the Program did not record the correct inspector names in IA. Program management told us that it recorded the names of different inspectors in IA so that multiple inspectors could have access to the records—even when some of these inspectors did not work on the inspections—because only inspectors listed in IA can access inspector records. The portion of available federal funds that the Program receives from PHMSA is based on its evaluation score of Program performance. As a result of misreporting, it appears that the Program may have received more federal funding than appropriate based on the details of Program activities and performance documented in its internal records. If PHMSA determines that the Program misreported information, PHMSA has the ability to require the Program to pay back federal grant funds and/or decrease the Program's future grant funds.

Why did these problems occur?

Overall, the Program misreported key information to PHMSA due to a lack of oversight and processes to ensure accurate reporting, as follows:

- **Lack of Department and PUC oversight of Program reporting to PHMSA.** The Department and PUC do not have sufficient processes to review and verify the information that the Program reports to PHMSA. For example, the Department and PUC do not have a process to review information on the Program's draft annual grant application or draft progress report, and reconcile the information to Program supporting documentation and data to check the accuracy. During the audit, Program management stated that PUC management and staff are able to access Program records, which would likely be needed for this type of review process. This type of Department or PUC oversight of federal reporting is important because Program management and staff told us that PHMSA's review process does not include analyzing the reliability of the Program's internal records, similar to the review conducted as part of our audit, to verify that Program reporting is accurate and complete. According to Program management, PHMSA typically conducts its evaluation in less than 1 week; thus, PHMSA would need to be able to rely on accurate and complete reporting by the Program and on the information that the Program records in the federal IA system.

- **Lack of sufficient Program procedures to maintain accurate and complete records needed to support federal reporting.** The Program has not implemented procedures to maintain records in accordance with federal requirements, including PHMSA Guidelines, in order to ensure accurate reporting on grant applications and progress reports. Additionally, the Program has not established consistent data entry guidance for recording Program information in IA.

Recommendation 7

The management and staff of the Public Utilities Commission should work with the Department of Regulatory Agencies to implement controls over the Gas Pipeline Safety Program's (Program) federal reporting by:

A. Implementing oversight processes of the Program's federal reporting, such as an annual quality check of the information that the Program is planning to report to the Pipeline and Hazardous Materials Safety Administration (PHMSA) on the Program's grant application and progress report, and the information recorded in the federal Inspection Assistant system, along with a check of internal Program data and documentation, to verify that the Program is reporting accurate and complete information to PHMSA.

B. Implementing procedures, including guidance for Program staff data entry, to ensure that the Program maintains accurate and complete data and documentation on its operations, in order to support the Program's performance and information reported to PHMSA.

Response

Public Utilities Commission and Department of Regulatory Agencies

A. Agree
Implementation Date: March 2024

The PUC will implement oversight of the process supporting federal reporting by the Program, including reviewing information supporting data calculations in the Program's grant application and progress report, and the information recorded in the federal Inspection Assistant system, and a reconciliation of that information with internal Program data and documentation, to verify that the Program is reporting accurate and complete information to PHMSA.

B. Agree
Implementation Date: March 2024

The PUC will update its State Agency's written Program Guidelines to implement procedures to provide guidance for consistent data entry to ensure the Program maintains accurate and complete data and documentation for reporting to PHMSA.

Finding 8—Inspector Conflicts of Interest

During Calendar Years 2021 and 2022, the Program documented that 12 different staff conducted inspections of gas pipeline operators. According to Program management and staff, as a matter of practice, the PUC attempts to hire former employees of operators to serve as Program inspectors. Program management stated that former operator employees should have a minimum of 3 to 5 years of industry experience for the PUC to hire them as a Program inspector to help ensure that they begin the job with some knowledge and skills needed to conduct pipeline safety inspections. In Calendar Year 2022, the Program hired five new inspectors, three of whom had previously worked for operators.

What was the purpose of the audit work and what work was performed?

The purpose of our audit work was to assess the Program's processes for identifying, assessing, and mitigating conflicts of interest for inspectors who inspect operators, and determine if any of the inspectors had conflicts of interest due to inspecting their former employers soon after being hired. We reviewed the Affidavit of Independence and Compliance forms that 12 Program inspectors signed in Calendar Years 2021 and 2022, on which the inspectors confirmed their understanding of the Department's conflict of interest policy and other ethical requirements. For the three inspectors who the PUC hired in Calendar Year 2022 and were previously employed by operators, we interviewed Program management and the inspectors, and reviewed the inspectors' public online LinkedIn employment profiles to determine when they worked for operators and when they began working for the Program. We reviewed the Program's Smartsheet data from Calendar Year 2022 to determine the extent to which inspectors had inspected their former employers.

How were the results of the audit work measured?

- **The Colorado Constitution, statutes, and Department policy collectively outline the expectation that state employees avoid conflicts of interest when conducting state business.** According to the State's Independent Ethics Commission, although Article XXIX of the Colorado Constitution does not use the phrase "conflict of interest," it states that government employees should avoid conduct that violates the public trust or creates a justifiable impression among the public that such trust is being violated [Colorado Constitution, Article XXIX, Section 1(c)]. To that end, state employees should conduct themselves pursuant to the standards outlined in Section 24-18-101, et seq. C.R.S., including the expectation that employees avoid conflicts of interest in carrying out state business. For example, statute prohibits employees from engaging in activities that create a conflict of interest with their state duties [Section 24-50-117, C.R.S.] and engaging in personal financial business with a person whom the employee inspects or regulates [Section 24-18-108(2), C.R.S.].

- **Department policy defines a conflict of interest for its employees.** Specifically, Department policy states that "There is a presumption of a conflict of interest and loss of independence when circumstances are such that the average reasonable individual would be led to believe that the employee's ability to make a fair and honest judgment in the public interest is or would be impaired" [Conflict of Interest Policy, February 2019]. This Department policy also states:

  - Department employees "shall maintain independence in both appearance and fact in the conduct of their duties."

  - All new hires to the Department are required to sign Affidavit of Independence and Compliance forms attesting that they have read the policy, and Department employees shall annually sign the forms. According to the Department, these forms help to ensure that employees are aware of and complying with state and Department policies, including the conflict of interest policy and other ethical requirements.

  - Each Department Division (including the PUC) may adopt additional polices that they feel are in the best interest of protecting the public.

- **The Program's unwritten policy is that, within an inspectors' first 6 months of hire, it does not assign them to inspect their former operator employer.** The PUC and Program have not adopted policies or guidance on employee conflicts of interest, beyond what the Department has developed. However, Program management stated that its goal is to have a 6 month cooling off period during which inspectors are not inspecting their former employers.

  Due to the lack of written PUC and Program policies and guidance on conflicts of interest, we looked to the State Controller's guidance as a general source of information to help determine if there were gaps in the Program's procedures for identifying and addressing conflicts. The State Controller's *Conflicts of Interest Technical Guidance*, issued in 2017, recommends that state agencies:

  - **Identify potential conflicts of interest.** For example, new employees should complete conflict of interest disclosure forms and update them as needed or at least annually.

  - **Review disclosed conflicts and possible conflicts of interest.** For example, supervisors should review conflict of interest disclosures to assess whether there is an actual or perceived conflict that requires mitigation.

  - **Mitigate an employee's conflict.** This could include making necessary modifications to the employee's duties to avoid the conflict.

What problems did the audit work identify?

Overall, we found that the three inspectors who were hired by the Program in Calendar Year 2022, and had been previously employed by operators, had conflicts of interest but the PUC allowed them to inspect their immediate former employer within 6 months of being hired. Exhibit 2.15 shows that, according to Program records, these three inspectors conducted 109 inspections of their immediate former employers within 6 months of working for those operators.

Exhibit 2.15
Summary of Inspections that Inspectors Conducted of Their Immediate Past Employers Calendar Year 2022

Program Inspector	Number of Inspections of Former Employer within Inspector's First 6 Months	Types of Inspections Conducted
Inspector A	15	Standard Operator Inspections and Distribution Integrity Management Inspections
Inspector B	1	Standard Operator Inspection
Inspector C	93	Standard Operator Inspections, Field Inspections, and Emergency Response Inspections
Total	**109**	**4 Types of Inspections**

Source: Office of the State Auditor's analysis of Program records.

After we reported these issues to the Program, management indicated that, for three of the 109 inspections we identified, they disagreed that Inspector A had an unmitigated conflict of interest related to the inspections that they conducted of their former employer because a trained supervisor had reviewed the results of the three inspections. However, the Program's records did not show evidence of supervisory review; the Program's administrative project coordinator, who is not a trained inspector, had signed-off as the supervisor on these three inspections.

For the remaining 106 inspections, management disagreed that the inspectors had unmitigated conflicts of interest for various reasons; however, the reasons did not eliminate or mitigate the conflicts. Specifically, for Inspector C, management told us that it had not been aware of the inspector's prior employment, but that a conflict had not existed because the staff member worked for the operator as a gas operations trainer only a short time (i.e., 1 month) prior to being hired by the PUC and inspecting their former employer. However, length of time of prior employment and position may not be sufficient to mitigate a conflict of interest related to a former employer. For Inspectors A and B, management reported to us that it did not believe there had been unmitigated conflicts because the inspectors had conducted most of the inspections without interacting with operator employees during the inspections; for example, the inspectors looked at operator equipment and documentation. However, lack of interaction with operator employees may not sufficiently mitigate conflicts of interest related to a former employer. For example, if the inspector had left the prior employment on particularly bad or good terms, there is a risk that it could influence how the inspector applies their discretion when determining operator noncompliance, as allowed by the Program's internal guidelines; this is discussed in our *Enforcement of Safety Regulations* Finding.

Additionally, we found that, although the 12 Program inspectors who were employed by the PUC in Calendar Years 2021 and 2022 had signed the Department's Affidavit of Independence and Compliance forms, none of them—including the three inspectors noted previously—disclosed their former employment with gas pipeline utilities. Additionally, while the Department and PUC stated that they regularly ask about prior employment during the hiring process, they did not have documentation to indicate that the inspectors had disclosed having potential or real conflicts of interest, or documentation that management had identified or considered whether or not the inspectors had conflicts.

Why did these problems occur?

Overall, the Department and PUC lack policies and procedures to identify when Program inspectors may have a conflict of interest related to the operators that they inspect or other conflicts, and to help prevent or mitigate conflicts. Specifically:

- **No Department-wide prohibition on employees regulating their immediate former employer soon after hire, or procedure for disclosing, assessing, or mitigating conflicts of interest.** The Department's conflict of interest policy does not prohibit its employees from regulating or inspecting their immediate former employer, or otherwise include guidance to help its divisions prevent and address these types of conflicts. Additionally, management may not be aware of conflicts of interest because the Department has not developed a policy or procedure for its employees to disclose their real, potential, and perceived conflicts of interest. For example, employees do not submit conflict of interest disclosures, and the Affidavit of Independence and Compliance forms that employees sign do not include space for them to disclose conflicts. Implementing a method for employees to submit written disclosure of their real, potential, and perceived conflicts to management would help the Department identify conflicts that may need to be addressed.

  The Department has also not developed policies, procedures, or other guidance to indicate the factors that management should consider when assessing whether an employee may have a conflict. During the audit, management indicated that factors that eliminated an inspector's conflict of interest when regulating their former employer included the inspector's length of time working for the regulated operator, the inspector's former role when working for the operator, and limited inspector interactions with the operator when conducting inspections. However, no statute or Department policy indicates that these are acceptable reasons for management to conclude that a conflict does not exist when an employee regulates their immediate former employer.

Lastly, the Department lacks guidance on ways that management could mitigate an employee's conflict of interest. For example, for three of the 109 inspections that we identified, management indicated that a supervisor's review of the inspection results was sufficient to eliminate the conflict; however, there is no policy, procedure, or guidance to help ensure that management consistently assigns a supervisor to review the work of employees when they regulate their former employers.

- **No PUC written conflicts of interest policies or procedures for its management or staff.** For example, the PUC has not developed a written policy or procedure to prevent inspectors from being assigned to inspect an operator with whom they may have a conflict or financial relationship.

  Other divisions within the Department have implemented written policies and procedures to help identify and prevent conflicts of interest related to their respective regulatory duties, which may serve as best practices for the PUC to consider when developing a conflict of interest policy that is tailored to the Program's needs. For example:

  - The Office of Enforcement's written policy states that a conflict of interest may exist when staff and a stakeholder had the same employer; staff should disclose the nature of potential conflicts of interest, such as when assigned an enforcement case; and that the Office's management shall review the disclosure and identify appropriate steps to mitigate or address a conflict.

  - The Division of Insurance's and Division of Banking's written policies require employees to disclose conflicts annually and prohibit their employees from exercising any regulatory control, inspecting, or examining former employers within certain timeframes of being hired.

  Federal regulations may also serve as best practice guidance for the PUC, given that the Program's inspectors help administer a federal program. Federal regulations reinforce the need for federal programs to have robust procedures to avoid conflicts of interest related to former employment, and state that federal employees should recuse themselves from working on a particular governmental matter involving specific parties if the employee has, within the last year, served as an employee of a party in such matter [5 CFR 2635.502(a) and (b)(1)(iv)].

- **The PUC has historically encouraged inspectors to have experience and familiarity with operators, which appears to have contributed to the lack of procedures to mitigate conflicts.** According to PUC and Program management and staff that we interviewed, the PUC has seen the relationship between an inspector and their former employer as beneficial, and that an inspector's prior industry experience helps them with the learning curve of understanding how to conduct inspections. Therefore, there has not been a concerted effort to ensure that Program inspectors do not have a conflict with the operators that they inspect.

- **Training for management and staff may be needed.** During the audit, Program management and staff did not appear to understand what constitutes a conflict of interest or the risk that it may pose in the regulatory environment. This indicates that management and staff could benefit from training on real, potential, and perceived conflicts of interest, including how to identify, prevent, and address them.

Why do these problems matter?

When inspectors have conflicts of interest related to the operators that they inspect, the following risks can occur:

- **Risk of Inconsistent, Biased Inspections.** The Department's primary responsibility is to regulate entities in the state, such as by conducting various inspections and reviews of entities. When the Department allows inspectors to inspect their recent former employers, there is a risk that inspectors will make biased decisions, either consciously or unconsciously, or report incomplete information, in favor of their former employers. For example, one inspector—Inspector C—who we identified as having a conflict of interest due to inspecting their former employer, did not record any noncompliance when conducting a total of 88 "design/testing/construction/repair" type inspections of their former employer during their first 6 months of PUC employment. However, a different Program inspector who was not a former employee of the operator, did record two instances of noncompliance within the same 6-month period when conducting 70 "design/testing/construction/repair" type inspections of this same operator. This indicates that there is a risk of bias or inconsistency when inspectors are inspecting their immediate former employer soon after hire.

  When conflict of interest policies and procedures do not ensure that inspectors disclose potential conflicts, and that management mitigates them, other risks include:

  - Financial interest bias when an inspector has an undisclosed personal financial interest in the operator. For example, some of the gas pipeline operators for whom Program inspectors were employed, are publicly traded companies, and the inspectors could have vested stock that may impair their independence. PUC management stated that, during interviews of potential job candidates, the PUC tells the candidates to divest any financial interest in a former employer before accepting a position with the PUC. However, the PUC did not have documentation to show that Program inspectors had attested to divesting after they were hired by the PUC.

- Inequitable inspections that detriment the operator. For example, if a Program inspector disliked their former employer, there is a risk that they could consciously or unconsciously treat the operator unfairly by understating the operator's compliance with regulations.

- Inspecting own past work. For example, there is a risk that the inspector could inspect their own past work and decisions soon after being hired by the PUC, if, when working for their former employer, the employee helped develop the operator's policies and procedures, reviewed or reported on operator safety, or trained operator staff.

- **Risk of Ongoing Safety Issues and Diminished Public Trust.** According to the State's Independent Ethics Commission, "Appearances of impropriety are generally referred to as 'perception issues' or 'violating the smell test.' They can weaken public confidence in government and create a perception of dishonesty, even among government officials who are in technical compliance with the law" [Advisory Opinions 11-11 and 17-10]. Although we were not able to determine whether the inspection results that were reported by the inspectors with conflicts were biased, the results give the appearance of bias. When there is an opportunity for inspectors to be biased when conducting their regulatory duties, it could result in noncompliance with pipeline safety regulations not being identified, reported, or addressed, which creates an increased risk to public safety. The potential of biased inspections can also lead to the appearance of impropriety that could diminish public trust in the PUC. One option to help control for possible inspector bias is to have a thorough training program for inspectors and robust supervisory review of the inspection results. However, as we discuss in our *Inspector Training and Supervision* Finding, the Program has not implemented consistent training or sufficient supervisory review of inspectors.

Recommendation 8

The management and staff of the Public Utilities Commission should work with the Department of Regulatory Agencies to develop and implement written policies, procedures, and training to mitigate and/or help prevent Gas Pipeline Safety Program inspectors from having conflicts of interest with the gas pipeline operators that they inspect. This should include written policies, and procedures or guidance, to help identify and mitigate real, potential, and perceived conflicts of interest.

Response

Public Utilities Commission and Department of Regulatory Agencies

Agree
Implementation Date: March 2024

The PUC will work with the Department to implement specific policies and/or procedures to help prevent Program inspectors from having conflicts of interest with the gas pipeline operators. Any policy and/or procedures will (1) at a minimum, meet Department-wide policies and/or procedures and (2) help identify and mitigate any real, potential, and perceived conflicts of interest. Training related to inspector conflicts of interest will be created and performed.

Recommendation 9

The Department of Regulatory Agencies should consider developing written policies and procedures to help ensure its employees who regulate entities in the state, do not having conflicts of interest due to regulating their former employers.

Response

Department of Regulatory Agencies

Agree
Implementation Date: December 2023

The Department agrees that improvements are warranted to help ensure its employees who regulate entities in the state, do not have conflicts of interest due to regulating their former employers. The Department will implement policies and/or procedures that (1) comply with Department-wide policies and/or procedures and (2) help identify and mitigate any real, potential, and perceived conflicts of interest. The Department will also review its existing written conflicts of interest policies, procedures, and processes and will make any necessary revisions that are identified.

Finding 9—Complaint Management

Complaint management is an essential component of government regulation because it can help responsible state agencies gather information about potential problems that affect the public and help ensure that any issues are resolved. The PUC's Gas Pipeline Safety Program is the state entity responsible for monitoring operators in Colorado to help ensure public safety [Section 40-2-115, C.R.S., and PHMSA Guidelines 2018 and 2021]. Therefore, the Program is the entity responsible for receiving, investigating, and resolving complaints related to gas pipelines and operators. For example, individuals may send the Program complaints about operators, possible leaks of gas pipelines, or exposed gas pipelines that may not appear to be buried safely.

There are several ways that members of the public can submit complaints related to gas pipelines. The PUC has a website that allows individuals to submit complaints related to public utilities. PUC staff monitor the complaints received through the webpage and forward them on to the appropriate PUC section or program. In addition, Program management and staff told us that they typically receive complaints via email and phone calls. Program staff may also learn about complaints submitted as comments during PUC proceedings on gas pipeline-related matters. According to Program staff, any of them may receive a complaint; however, one staff member told us that they have primary responsibility for following up on complaints. Staff said that they follow up on complaints as they see fit, and that the PUC could penalize an operator if the Program finds that the complaint related to the operator's noncompliance with a safety violation.

What was the purpose of the audit work and how were the results measured?

The purpose of the audit work was to evaluate the effectiveness of the Program's processes for managing complaints related to gas pipeline safety, based on the following:

- **The Program should investigate and resolve complaints that it receives.** According to state regulations, public complaints that may affect gas pipeline safety, and that are verified by the Program, should have follow up through an inspection or investigation. Specifically, Colorado regulations state, "Inspections and investigations are necessitated by the existence of…a complaint received from a member of the public and verified by the [Program] as related to a jurisdictional pipeline facility and involving a discrete and auditable matter potentially impacting public safety" [4 CCR 723-11013(c)]. Additionally, statute states that complaints submitted by a larger group of gas customers should be resolved before an operator may change the rates that they charge customers [Section 40-3.5-104(4), C.R.S.]. Based on these requirements, the Program should have processes to review the complaints received to verify that they involve issues within the Program's jurisdiction, investigate and resolve any complaints that are verified, and assess whether the Program has received a large number of complaints related to a particular operator that would need to be resolved before a rate change can occur.

- **Compliant resolution should be timely.** According to the Department of Regulatory Agencies' annual Performance Plans for Fiscal Years 2021 through 2023, complaints from consumers guide the Department's ability to identify and carry out enforcement against businesses that are out of compliance with laws and regulations, and resolution on complaint matters should be timely. Within the Performance Plans for these years, a strategic performance measure for the PUC has been to resolve 99 percent of public utilities' complaints and inquiries within 15 days.

- **Complaint information should be maintained to facilitate inspections and investigations, and ensure resolution.** As discussed previously, some gas pipeline complaints may require a Program investigation of the complaint matter to resolve. For example, if an individual complains that they believe there was an explosion due to a gas leak, the Program may need to investigate. In other instances, according to PHMSA, the Program may need to conduct an inspection of an operator, such as of their safety policies or equipment, due to public complaints [4 CCR 723-11013]. Tracking all complaints received is key to ensuring that Program staff review the complaints and take appropriate action, such as by investigating and resolving the complaint issue, or following up on the issue when conducting operator inspections. In addition, PUC policy requires that its sections, including the Program, retain informal complaint documents and correspondence for a minimum of 3 years.

What audit work was performed and what problems were identified?

Overall, we found that the Program does not have effective processes for managing complaints. The Program does not track the complaints that it receives and could not provide information on what steps, if any, were taken to investigate and resolve complaints that it may have received. Specifically, we found:

- **The Program does not maintain information on the complaints that it has received.** We requested that the Program provide data or documentation on all complaints received in Calendar Years 2018 through 2022. According to Program management, they were unable to find information on complaints received related to gas pipeline safety and were unsure where the information may be saved, although multiple staff told us that they recalled receiving complaints during the period of our review, including in recent years. Program management did not know how many complaints the Program had received, what issues and operators were the subject of the complaints, what steps staff took to review or investigate the complaints, or how the complaints were resolved.

  Since the Program was not able to provide information on complaints, we reviewed documentation related to PUC gas pipeline proceedings, and information that staff stored on the Program's shared network drive. We identified three complaints that the Program received in

Calendar Years 2018 through 2020, but Program management indicated that they were not aware of them. In addition, we met with three individuals who were referred to us by a legislator—one individual who submitted one of the three complaints to the PUC through a proceeding, and two other individuals who provided documentation to show that they had submitted two different complaints to the Program in Calendar Year 2021, although they stated that neither complaint had been addressed by the Program.

- **The Program does not appear to follow up on or resolve complaints.** For the five complaints that we identified, we found the following problems:

  - One complaint from 2018, which alleged that public operator Colorado Natural Gas was not maintaining gas pipelines properly, was emailed to the Program manager, a Program staff, and subsequently sent to the PUC as public comment for a PUC proceeding related to the operator. Program staff indicated that former management instructed the staff to not respond to the complaint. In 2019, the PUC held another proceeding related to Colorado Natural Gas, which resulted in the PUC penalizing the operator $1.125 million in order to encourage compliance with safety regulations; the then-Program Chief/Manager subsequently recommended that the PUC Commissioners reduce the penalty to $5,000, which the Commissioners approved.

    Two additional complaints from two complainants who we met with, had records showing that, in 2021, they emailed the Program complaints related to safety issues with this same operator. These complainants stated that they did not receive any response from the Program and that the concerns they had reported to the Program had not been addressed by Colorado Natural Gas. Program records show that Colorado Natural Gas had the second-most instances of repeat noncompliance in Calendar Years 2020 through 2022.

  - For another 2018 complaint, which alleged possible gas leaks that had not been addressed by public operator Xcel Energy for several years, we found documentation to show that the Program validated the complaint and sent the operator a request for information that referred to the complaint. However, the Program did not maintain information on the original complaint, such as when it was received, the complainant, the operator's response, or a resolution.

  - One complaint from 2020, which alleged that public operator Xcel Energy violated safety regulations related to gas pipeline meters, was anonymously submitted to the PUC through its Website, and forwarded to the Program by an employee who monitored the site. The Program could not provide any documentation to show that the complaint had been reviewed, investigated, followed up on, or resolved.

In addition to these problems, we could not determine the extent to which the Program had addressed any complaints timely because it did not track information on the timeliness of complaint resolution. Therefore, we could not determine whether complaints were resolved within 15 days, in accordance with the Department's performance measure for the PUC.

Why did these problems occur?

The Program lacks policies, procedures, and tools for managing complaints, as follows:

- **The Program lacks procedures for documenting, tracking, reviewing, and resolving complaints.** The Program lacks written guidelines and procedures for tracking, reviewing, and resolving complaints, or for staff to address a complaint within a certain time frame to ensure prompt action is taken. In addition, the Program has not implemented guidelines or procedures requiring staff to document complaints received and the actions taken to address them, and it has not provided training to staff on complaint management. The staff member who told us that they are primarily responsible for receiving and following up on complaints said that they had not been tracking complaints or their actions to follow up because they had not been instructed to maintain documentation, and it had not occurred to the staff to do so. Two other staff who told us that they had received and handled complaints, said that they were not sure if any records had been kept. Program staff also said that management does not oversee complaint handling to verify that staff handled or addressed each complaint. At the end of our audit, Program management stated that it had drafted a complaint handling process, but the draft did not cover each of the areas above, and a process had not been implemented.

- **The Program lacks a tool for tracking and managing complaints.** The Program has not developed a tool, such as a spreadsheet or database, for staff to document information on complaints received and the Program's actions taken to resolve the complaints. Basic complaint management includes: (1) tracking all complaints that are received in a centralized location to ensure that management and staff can access and review the information; (2) tracking the complainant's contact information, date received, nature and urgency of the complaint, how the complaint was investigated or verified, and the resolution and resolution date; and (3) providing staff guidance on tracking complaints consistently and timely.

- **The Program does not review complaint information to identify trends with operators or safety concerns.** Due to the Program's lack of complaint documentation and procedures for managing complaints, Program management and staff have no process to review complaint information to identify underlying patterns or trends with operator safety that may need to be addressed. As such, the Program cannot consider such trends when planning its inspections or investigations of operators, or when considering rate changes that operators request, as required and discussed in our previous findings.

Why do these problems matter?

When the Program does not have evidence that it consistently follows up on and resolves complaints, the issues identified in the complaint may continue, creating an increased risk to public safety. In addition, when the Program does not maintain information on the complaints it has received, it does not know the reason for or subject of the complaints, how many it has received, or whether they have been addressed timely, or at all. The Program also does not have complete information on the number and type of complaints received for each operator, which can be important information for the PUC to consider when operators are requesting to increase their rates.

When the Program does not track information on complaints and the actions taken to address them, the Program also cannot analyze the types of complaints received and use that information to help plan risk-based inspections, as PHMSA requires. For example, analyzing complaint data can help Program staff identify trends and ongoing problems with certain operators or identify internal improvements to procedures that may be needed. Further, when the Program does not consistently follow up with complainants, they may continue to submit complaints for the same issue because they do not know if it has been resolved or is in the process of being resolved.

Finally, review of complaints by multiple staff, with no formal complaint management procedures or tools, and insufficient complaint documentation, increases the risk of inconsistencies in complaint handling and the risk that complaints may not be sufficiently addressed.

Recommendation 10

The management and staff of the Public Utilities Commission should work with the Department of Regulatory Agencies to ensure that the Gas Pipeline Safety Program (Program) improves its management of complaints by:

A. Developing and implementing written Program procedures for consistently maintaining information on the complaints received, and for reviewing, investigating, and resolving them. This should include implementing reasonable timeframes for addressing complaints, communicating the resolution to complainants when appropriate, and overseeing staffs' complaint handling to ensure that they take sufficient action to follow up on and resolve complaints.

B. Developing and implementing a tool, such as a spreadsheet or database, for the Program to consistently track the complaints received, and action taken to address them, in a central location.

C. Training appropriate Program management and staff on the written policies and procedures and tracking tool developed in Parts A and B above.

D. Implementing Program processes to periodically review complaint data to identify operator or other safety trends that may need to be addressed, and taking action as needed.

Response

Public Utilities Commission and Department of Regulatory Agencies

A. Agree
Implementation Date: March 2024

The PUC will work with the Department to ensure that the Program improves its management of complaints. The PUC will update its State Agency's written Program Guidelines to implement written procedures to document complaints received, to track complaints, to review, to investigate, and to resolve them. The written procedures will identify expected timelines to address each complaint, consider surrounding circumstances, communicate the resolution of the complaint, and manage review of the process.

B. Agree
Implementation Date: June 2024

OIT currently anticipates that the software application being developed by Hyland will include complaint tracking. However, the PUC will develop and implement a spreadsheet or database process to record complaints, documenting the review and resolution thereof, including the reasonableness of timeframes to resolve each complaint. Management and the Program will periodically review performance of the process. While implementation will begin under existing systems, full implementation will likely not be able to be completed until completion of systems development by OIT.

C. Agree
Implementation Date: March 2024

The PUC will update the State Agency's Program Guidelines to include policies and procedures implementing the tracking tool developed in Parts A and B above and will conduct periodic staff training on implementation.

D. Agree
Implementation Date: March 2024

The PUC will update the State Agency's written Program Guidelines to include policies and procedures implementing the tracking tool developed in Parts A and B above, including periodic review of complaint data. Appropriate action will be taken based upon this review.

Finding 10—Program Management and Oversight

According to the National Association of Pipeline Safety Representatives' Website, state gas pipeline safety programs are intended to ensure safety and give the public confidence that the gas pipeline system is safe and reliable, and state pipeline inspectors are the "first line of defense" at the community level to enforce pipeline safety. State gas pipeline safety programs also provide a local presence for protecting the public from gas pipeline accidents.

As discussed throughout the audit findings, Colorado's Gas Pipeline Safety Program, administered by the PUC and overseen by the Department, must adhere to federal and state requirements, and must operate effectively to help ensure the safety of the gas pipelines that are within the State in a manner that protects the public [49 USC 60105; 49 CFR 171.1; and Section 40-2-115, C.R.S.].

What was the purpose of the audit work, what work was performed, how were the audit results measured?

The purpose of the audit work was to assess whether the PUC has managed and overseen the Program effectively, in accordance with federal requirements and legislative intent to enforce gas pipeline safety requirements and help ensure that the public is protected. We also assessed whether the Department sufficiently oversees PUC and Program practices to ensure that the Program operates in accordance with the regulatory intent, as well as the purpose and mission of the Program to have a systematic inspection, evaluation, and compliance structure that:

- Understands risks posed to public safety by the construction, operation, and maintenance of intrastate gas pipeline systems in Colorado;
- Determines the efficacy of operators' procedures, processes, and actions in minimizing public safety risks associated with these systems; and
- Advocates for risk-minimizing changes to operator procedures, processes, and actions and/or the punitive assessment of penalties [Colorado Program internal guidelines].

According to PHMSA, the state agency that assumes responsibility for administering the Program should apply sound management practices and ensure that the Program operates in accordance with Program objectives and applicable federal guidelines and regulations/rules. As the administrator of the federal-state Program, the PUC is responsible for developing a system of management practices and internal controls, including a series of policies, procedures, actions, and activities across the Program's operations, to ensure that it operates effectively and in accordance with applicable laws, regulations, and guidelines. Further, best practices for program management in Colorado government agencies are identified in the SMART Government Act [Section 2-7-201, et seq., C.R.S.]. The SMART Act identifies the elements of a well-managed government program, which includes having standardized program oversight processes, tools, and practices that aid program implementation to

ensure overall effectiveness in achieving legislative intent and the performance goals.
To evaluate management and oversight of the Program, we assessed the overall audit evidence, including information provided by the PUC and Program management and staff through documentation, data, interviews, and written comments. We assessed the Program's policies, procedures, and practices, and the state regulations and internal guidance that the Program developed for Calendar Years 2017 through 2022. We also reviewed Department and PUC policies in certain areas, such as records management, employee conflicts of interest, and accounting for penalties. We compared the PUC's practices for administering the Program to applicable policies and to federal laws, regulations, guidance, and grant agreements for the State's administration of a gas pipeline safety program. Additionally, we reviewed PHMSA performance evaluations of the Program for Calendar Years 2019 through 2021, and conducted interviews with staff from PHMSA to gain a general understanding of how the State should administer the Program under federal guidance and oversight. We reviewed relevant strategic performance measures for the PUC and the Program, which the Department reported in its annual SMART Act Performance Plans for Fiscal Years 2021 through 2023. We also met with Department management to understand how it oversees the PUC, and measures PUC and Program performance.

What problems did the audit work identify and why do they matter?

Throughout this audit, we identified problems in Program operations, which collectively demonstrate that the Program has not sufficiently met federal and state requirements, or legislative intent, to help ensure gas pipeline safety in Colorado. Specifically, the audit identified problems in each area reviewed, finding that the Program lacks adequate practices and processes for:

- Inspecting operators,
- Enforcing safety requirements,
- Assessing and collecting penalties from operators for noncompliance,
- Investigating safety accidents related to operators and pipelines,
- Ensuring its inspectors are trained and/or supervised,
- Ensuring its inspectors do not have conflicts of interest when conducting inspections,
- Reporting Program information and performance as part of federal grant requirements, and
- Managing complaints from the public related to operators and gas pipeline safety.

As we discuss throughout the audit findings, management and staff have not retained or managed Program information in a manner that demonstrates that the Program fulfills its mission to understand risks posed to public safety; regulate operators and monitor their noncompliance with safety requirements to minimize public safety risks; or advocate for risk-minimizing changes to operator procedures, processes, and action. During the audit, the Program was unable to provide the audit team a range of historical information on operations between Calendar Years 2017 through 2022, such as complete records of operator inspections, actions taken to enforce operator compliance with safety requirements, and safety accidents and related investigations by the Program.

Program management also told the audit team that inspection data and documentation from 2017 through 2019 were missing or incomplete because the former Program Chief/Manager retired without documenting the information in Program systems or providing any records to the Program staff. The State needs this information to monitor operator practices and compliance over time, and ensure that appropriate action is taken to regulate and enforce compliance. In addition, the Program has maintained information on its operations inconsistently using multiple methods, databases, and systems over the past several years.

Further, as discussed in the findings, PHMSA has identified ongoing Program noncompliance with federal requirements. For example, PHMSA's annual evaluations of Program performance and operations for Calendar Years 2019 through 2021 included 14 findings related to the Program's noncompliance with federal requirements and guidelines. Most of the issues that PHMSA identified are consistent with concerns identified in our current audit, including weaknesses in the Program's inspection records, enforcement actions, accident investigations, and inspector training, and a lack of state regulations complying with federal regulations. Based on our performance audit results, it does not appear that the Program addressed five of these findings within the required 1-year period established by PHMSA, as the Program agreed to, although the Program has reported to PHMSA that it has addressed all of these findings. Despite recurring problems in the Program—and the Program's agreement to address the prior federal findings—our current audit findings demonstrate that the Program has not taken sufficient steps to address the problems identified and to strengthen its operations.

The PUC and Department have a duty to Coloradans and the taxpayers who provide the federal and state funding for this safety Program to ensure that Program efforts are focused on protecting the people of Colorado. The PUC and Department also have the responsibility to the operators to consistently and fairly regulate operator systems, procedures, and practices. In establishing the Program within the PUC, the General Assembly vested the Department with broad responsibilities for carrying out the Program in accordance with federal grant requirements and state requirements, and for managing an average of about $1 million in federal and state Program funding annually. Comprehensive steps to improve Program operations are needed to help ensure that the Program fulfills legislative intent and federal requirements, and to help ensure accountability to taxpayers for the meaningful and effective use of these public funds.

Why did these problems occur?

Overall, the problems identified by this performance audit and by PHMSA signify the need for improved Program management and oversight. We found that the problems occurred because the PUC and Department have not established effective processes to help ensure the Program carries out its responsibilities under federal and state laws and regulations. Specifically:

- **PUC management has not sufficiently overseen Program operations.** PUC management has not implemented sufficient processes to oversee the Program to help ensure that it complies with applicable requirements and performance measures for operating this federal-state program. PUC management appears to have allowed Program management significant latitude with respect to administering the Program, and it has not established sufficient mechanisms to monitor operations so that Program management can be held accountable for complying with federal and state requirements. During the audit, PUC management indicated that they did not have sufficient knowledge of how the Program operated, and they relied on Program management and staff to ensure that operations were appropriate. PUC management seemed to have a general misunderstanding about the Program, including that the Program operates under a federal grant and, therefore, must comply with federal requirements; management incorrectly reported to the audit team that the Program had discretion to comply with federal requirements, and that the PUC's focus is adhering to state statutes and state regulations. In March 2023, PUC management also told us that it did not believe that the Program needed to follow PHMSA Guidelines. According to PUC, "our performance should be based on the processes and procedures as outlined in the program/state specific guidelines" and "[PHMSA] guidelines are not enforceable." This fundamental misunderstanding of the requirements that Colorado must follow to carry out this federal-state Program under the federal grant appears to be at least part of the reason why PHMSA annual evaluations have found that the Program has not consistently followed federal requirements—and why the Program continues to need improvements in key areas of its operations.

  Additionally, the PUC does not appear to have sufficient processes to monitor the PHMSA findings issued in annual Program evaluations, or the steps taken by the Program to address the findings. To do so, PUC management may need improved processes to gather information on each finding and on the specific steps that the Program has taken to address the problems identified.

- **The Department has not sufficiently exercised its oversight authority over the PUC to help ensure accountability.** The Department has allowed the PUC autonomy in administering the Program without sufficient processes to ensure that the Program is compliant with applicable laws, regulations, and guidance, and meets Department performance measures for regulating operators and protecting the public. For example, the Department has not implemented sufficient processes to obtain updates from the PUC on the extent to which the Program is operating in accordance with performance requirements and measures, or to hold PUC management accountable for adhering to requirements that the State must follow in order to receive federal funds. As discussed in Chapter 1, state statute classifies the PUC as a type-1 entity within the Department, meaning the Commissioners generally exercise their powers and duties to regulate and promulgate regulations/rules independent of the Department [Sections 40-2-101 and 24-1-105, C.R.S.]. However, the PUC's functions fall under the Department's purview and, since PUC staff *are* Department staff, the Department has the authority to improve its oversight of PUC programs and staff. Until the PUC improves how the Program is managed and overseen, including its management of key information used to run and support its operations, it may be challenging for the Department to monitor Program performance. Nonetheless, it will be important for the Department to implement greater oversight of the PUC to help ensure that the Program operates effectively.

Recommendation 11

The management and staff of the Public Utilities Commission (PUC) should work with the Department of Regulatory Agencies (Department) to improve the State's administration of the Gas Pipeline Safety Program (Program) by:

A. Establishing and implementing processes that provide ongoing oversight and monitoring of the Program's operations and performance to help ensure it is administered in line with applicable federal and state laws and regulations, federal and Program guidelines, and any applicable Department and PUC policies. This should include a process for PUC management to ensure it has a sufficient understanding of how this federal-state program should operate.

B. Establishing and implementing a plan to monitor the Program's progress in implementing federal evaluation findings, and the Office of the State Auditor's audit recommendations, to ensure the findings are fully addressed and any recommendations are implemented timely and effectively.

Response

Public Utilities Commission and Department of Regulatory Agencies

A. Agree
Implementation Date: March 2024

The PUC will work with the Department to improve the State's administration of the Program. The PUC will update the State Agency's written Program Guidelines to include a Quality Assurance (QA)/Quality Control (QC) process to be performed at prescribed intervals by both the Program and PUC management.

B. Agree
Implementation Date: March 2024

The PUC will work with the Department to update the State Agency's written Program Guidelines to include a written process to be performed at a prescribed interval by the Program, PUC management, and the Department to ensure that PHMSA and OSA recommendations are implemented.

Recommendation 12

The Department of Regulatory Agencies should improve its oversight of the Public Utilities Commission (PUC) staff to help ensure they administer the State's Gas Pipeline Safety Program (Program) to regulate and enforce pipeline safety in line with applicable laws, regulations, policies, and guidance. This should include, but need not be limited to, establishing processes to obtain PUC updates on Program performance, and hold PUC management accountable for adhering to the federal grant requirements that the State must follow.

Response

Department of Regulatory Agencies

Agree
Implementation Date: March 2024

The Department agrees to improve its oversight of the PUC staff by establishing processes and procedures to obtain PUC updates on Program performance and hold PUC management accountable for adhering to the federal grant requirements that the State must follow.

Appendix A

Appendix A
Natural Gas/Propane Operators in Colorado[1]
Calendar Year 2022

Public Operators	Public-Municipality Operators	Private Operators[2]
Aka Energy Group	Center Municipal Gas System	Audubon Gardens Apartments
Atmos Energy Corporation	City of Colorado Springs, Colorado Springs Utilities	Campion Academy
Black Hills Energy	City of Trinidad	Cheyenne Mountain Estates
Black Hills Service Company	City of Walsenburg	Circle Drive Mobile Home Park
Bonanza Creek Energy Operating Company	Fort Morgan Gas Department	Coates Cabins
Chevron	Ignacio Municipal Gas	Denver Cascade Mobile Home Park
Colorado Natural Gas	Lamar Utilities Board	Dotsero Mobile Home and RV Park
Colorado Sand Company	Town of Aguilar	Durango Mountain Utility
Crestone Peak Resources	Town of Rangely	Front Range Mobile Home Park
DCP Midstream	Town of Walden	Gateway Canyons Resort
Divide Creek Gathering System		Golden Hills Mobile Home Park
Elevation Midstream		High Peak Camp and Conference Center
Enterprise Products Operating		Lakeside Cottages
Foundation Energy Management		Longs Trailer Court
Fountain Valley Power		Meadowbrook Mobile Home Camp
Fundare Resources Operating Company		Mount Aire Mobile Home Park
Harvest Midstream Company		Pinions of Turkey Canyon
Hilcorp Energy Company		Pleasant View Mobile Home Park
Ladder Creek		Ridgewood Mobile Home Park
Noble Energy		Salida Housing
Ogris Operating		South Park Mobile Home Park
Platte River Power Authority		YMCA of the Rockies
REP Processing		
Rocky Mountain Midstream		
Rocky Mountain Natural Gas		
Simcoe		
Sterling Ethanol		
Summit Midstream Partners		
Tenderfoot Pipeline Company		
Western Midstream Partners		
Williams Field Services		
Xcel Energy, Public Service Company of Colorado		
XTR Midstream		

Source: Office of the State Auditor's analysis of the Gas Pipeline Safety Program's records.

[1] Operators of natural gas and/or propane that have been inspected by the Program through the end of Calendar Year 2022.
[2] Private operators of master metered systems or liquid propane gas distribution systems.

Office of the State Auditor
State Services Building
1525 Sherman Street, 7th Floor
Denver, CO 80203

tel.
303.869.2800

email
osa.ga@coleg.gov

website
www.colorado.gov/auditor

linkedin
www.linkedin.com/company/colorado-state-auditor

twitter
@CoStateAuditor