BHCG (2023-2027) Five Year System Safety and Integrity Rider ("SSIR") Plan

November 1, 2022

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I. INTEGRITY MANAGEMENT PLAN HISTORY

In December 2003, the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration ("PHMSA") published the Gas Transmission Integrity Management Rule, commonly referred to as the TIMP Rule. The TIMP Rule specifies how pipeline operators must identify, prioritize, assess, evaluate, repair and validate the safety and integrity of gas transmission pipelines.

In December 2006, Congress passed the Pipeline Inspection, Protection, Enforcement and Safety Act ("Pipes Act"), which mandated that PHMSA prescribe minimum standards for pipeline system safety and integrity management programs for distribution pipelines to ensure fitness for service. The law provided for PHMSA to require operators of distribution pipelines to:

- Continually identify and assess risks on their distribution lines;
- Remediate conditions that present a potential threat to pipeline system safety and integrity; and
- Monitor program effectiveness.

In December 2009, as mandated by the PIPES Act, PHMSA published the Integrity Management Program for Gas Distribution Pipelines Rule, commonly referred to as the DIMP Rule. The DIMP Rule required operators to develop, write and implement a distribution pipeline system safety and integrity management program. Federal regulations require that operators identify risks to their pipelines where an incident could cause serious consequences, focus priority attention in those areas, and implement a program to provide greater assurance of the integrity of the pipeline.

In response to these federal mandates as required by PHMSA, Black Hills Colorado Gas, Inc. ("BHCG" or the "Company") developed its' Distribution Integrity Management Plan ("DIMP") and Transmission Integrity Management Plan ("TIMP"). The DIMP and TIMP require the utility to identify, assess, prioritize, and evaluate risks to the integrity of distribution and transmission lines and associated facilities and the manner in which those risks will be mitigate or eliminated. The integrity management approach under the DIMP is designed to promote continuous improvement in pipeline safety by requiring operators to identify and invest in risk control measures beyond core regulatory requirements. The integrity management approach under TIMP encompasses both "covered segments" of transmission pipeline within High Consequence Areas ("HCAs") and "non-covered segments" that fall outside of HCAs.

The DIMP and TIMP were created to proactively improve the integrity and safety of the pipeline through the following three key directives:

- Know your assets;
- Identify the risks and threats to those assets; and
- Be proactive in addressing those threats.

The Company's integrity management plans for its distribution and transmission assets include detailed written plan documents that formalize the Company's strategy for identifying, prioritizing, and proactively removing risk from its system. The DIMP (Confidential Attachment C.3) and TIMP (Confidential Attachment C.4) apply to all of BHC's distribution and transmission assets across six different states which includes BHCG's distribution and transmission assets in Colorado. These plans are reviewed annually and edited as necessary when rules change and as more data is gathered and analyzed both qualitatively and quantitatively. The documents also serve as the formal plans to comply with federal regulations regarding integrity management and are the foundation for BHCG's Five Year SSIR Plan. The DIMP and TIMP detail the Company's strategy for identifying and then removing the riskiest parts of its system while also providing guidance on processes to maintain existing system integrity through risk prevention and mitigation.

A. Transmission Integrity Management Plan

The TIMP complies with federal regulations that prescribe how operators validate the integrity of their gas transmission assets as defined by Title 49 Code of Federal Regulations ("CFR") Part 192, Subpart O ("TIMP Rule"), with the highest priority given to those located in high consequence areas ("HCAs"). The Company's TIMP addresses these integrity management requirements in addition to detailing its methods for addressing the nine primary potential threats described by the TIMP Rule. The written TIMP applies only to transmission assets as defined by 49 CFR § 192.3.

These regulations reference elements from the American Society of Mechanical Engineers ("ASME") B31.8S which contains principles and processes for pipeline operators to follow when developing and implementing an effective integrity management program. The Company considers these federal regulations as the minimum standard for developing and implementing the TIMP. It is this guidance, along with the directives within the Company's TIMP to identify, assess, and remove highest priority threats first that help drive the selection of SSIR projects within each year of the Five Year SSIR Plan.

The BHC TIMP is included as Confidential Attachment C.4 and was last edited July 22, 2022.

B. Distribution Integrity Management Plan

BHC's DIMP complies with federal regulations prescribing the maintenance of distribution pipelines. As previously described, as mandated by the PIPES Act, PHMSA published the Integrity Management Program for Gas Distribution Pipelines Rule, commonly referred to as the DIMP Rule requiring operators to develop, write and implement a distribution pipeline system safety and integrity management program.

The guidance in the federal regulations, along with the directives within the Company's DIMP to identify, assess, and remove highest priority threats first, help drive the selection of SSIR projects within each year of the Five Year SSIR Plan.

The BHC DIMP is included as Confidential Attachment C.3 and was last edited October 12, 2020.

II. COMPANY'S PROGRAMMATIC APPROACH

The Company developed integrity management programs of work in order to address risks and threats to assets discovered in the Company's DIMP and TIMP. The Company's integrity management programs by integrity management plan are as follows:

Table 1 – BHCG's Integrity Management Programs

DIMP	TIMP
Third Party Damages	Third Party Damages
Thin-Walled Tubing (x)	Top of Ground
Thin-Walled Steel (x)	Vintage Pipe (x)
Poorly Coated Steel (x) (Broadly defined as Vintage Steel)	Span and Exposed Pipe Replacement (x)
Encroachment	Safety Valves
Regulator Station Barricades (x)	Drip Legs
At-Risk Meters	Aerial Patrols
At-Risk Meters – with Problematic Pipe	Line Heaters
Farm Taps	Strain Gauge Location
High Pressure Distribution At-Risk Meters	Compressor Station Review
Vintage TBS/DRS Equipment Replacement (x)	AC Mitigation
Span and Exposed Pipe Replacement (x)	Data Improvement
Unlocatable	Piggability
Obsolete Mechanical Fittings	Liquids
Bare Steel – Protected (x)	
PVC	

DIMP	TIMP
Casings	Vintage Pipe
Vacant Risers	
Isolated Steel	
Emergency Valves	
Atmospheric Corrosion	
Cathodic Protection (x)	
Service Regulators	
At-Risk Meters Inside Meters	
5 PSIG Meter Sets	

Program development requires the coordination and collaboration of multiple departments in which subject matter experts ("SMEs") assess the necessity and priority for all programs. The process begins with the engineering department reviewing data, such as leaks on the system, characteristics of pipe, known damages and issues on the system, and running that data through a risk model. The output of the analysis is the focus of annual risk meetings with the operations department in which SMEs sequence, develop, define and prioritize integrity management programs to address risks on the system.

III. RISK MODEL

The Company has developed a detailed DIMP risk model and is developing a similar TIMP risk model. The model analyzes data based on 75 questions representing different threats to develop a risk score. Each question evaluates the following three separate factors to contribute to the risk score: Likelihood, Consequence, and Asset Consequence. The model evaluates threats on a broader level, or Data Area, but can also provide risk scores to specific pipe segments.

Data areas are determined by the pertinent information regarding the project. There are some data gaps due to the fact that the risk model is tied specifically to pipelines only. For targeted pipeline replacements, the Company utilizes the polygon areas for replacement, which relates directly to the pipeline replaced. Projects relating to above ground assets utilize the overall city ranking of all pipes in that location. This was done due to a lack of specific above ground facility risk rankings and trying to use the upstream and downstream piping impacted by a potential above ground incident.

PHMSA requires operators to consider the following eight primary threat categories in 49 C.F.R. Part 192, Subpart P:

- Corrosion Failure;
- Pipe, Weld, or Joint Failure;
- Natural Force Damage;
- Equipment Failure;
- Excavation Damage;
- Incorrect Operation;
- Other Outside Force Damage; and
- Other Cause

As previously mentioned, the outcome of the risk model calculations is one input when prioritizing projects. An overview of the risk models can be found in the Company's DIMP and TIMP.

Risk is calculated by evaluating the likelihood of failure ("LOF") and the consequence of failure ("COF"). Pipeline segments are scored in both the DIMP and TIMP risk model providing analysis of various threats and consequences to determine the overall pipeline segment risk score. LOF evaluates the likelihood of a particular threat by assigning a likelihood score for each potential sub-threat in the risk model. The likelihood score is developed from SME input, operator data such as leak and damage history, or GIS layers such as flood plains and earthquake zones. Several sub-threats include responses for mitigative measures that the Company has implemented. These measures help to reduce the relative risk for the given segment which is represented by negative index scores that are associated with those measures. An additional proactive measure to identify segments that are indicative of potential future failure, was to develop pipe profiles based on leak and damage history. Consequence, or COF, scores are an additive combination of threat consequence and asset consequence. Threat consequence is the severity of the impact of a failure or situation caused by each individual threat. Threat consequence scores are assigned based on a total failure, partial failure, or minimal/temporary failure of the segment. Asset consequence is the consequence of an event due to the characteristics or location of the given segment. Asset consequence consideration includes pressure, material type, pipe diameter, population density, ability to isolate the segment, and proximity to infrastructure.

Results are then stored in a geodatabase and can be presented in a variety of ways. The results can be viewed and analyzed in a large table, on a GIS map, or in a combined approach. The model can filter the risk results by material, age, and any threat category, or data area. The tables allow for analysis and statistical review utilizing a relative tiered approach. The results can also be color coded and viewed on a map.

Relative risk scores are divided into four statistically determined tiers with Tier 1 including the highest risk scores and Tier 4 including the lowest tier scores. Tiers are determined based on P90 risk scores such that Tier 1 includes the top 5% highest risk segments, Tier 2 includes the next highest 20% of segments, Tier 3 includes the next highest 25% of segments, and Tier 4 includes the lowest 50% of segments. Accordingly, Tiers 1 and 2 are considered high risk, Tier 3 is medium risk, and Tier 4 is low risk. The table below defines the tier structure with associated risk scores for DIMP and TIMP.

Table 2 – DIMP Risk Tiers

Tier	Top Risk	Bottom Risk	Risk Threshold	Risk Rank
1	3,426.70	3,129.40	Top 5% (95%-100%)	High
2	3,129.40	1,902.70	Next 20% (75%-95%)	High
3	1,902.70	1,436.70	Next 25% (50%-75%)	Medium
4	1,436.70	789.60	Lowest 50% (0%-50%)	Low

Table 3 – TIMP Risk Tiers

Tier	Top Risk	Bottom Risk	Risk Threshold	Risk Rank
1	2,243.50	1,708.85	Top 5% (95%-100%)	High
2	1,708.85	1,339.50	Next 20% (75%-95%)	Medium
3	1,339.50	1,211.50	Next 25% (50%-75%)	Low
4	1,211.50	785.40	Lowest 50% (0%-50%)	Low

Within P90 risk modeling, threats with unknown data are assigned the highest risk score. The pipelines have been installed over decades with inconsistent data collection over the lifetime of the pipeline systems. A lack of data does not indicate a lack of specific threats to a pipeline. Therefore, the risk model takes this into consideration and where a threat lacks the appropriate data source, there is a “P50” and “P90” score generated. The “P90” score treats unknowns as a top threat while “P50” treats unknowns as an average threat on a 1 to 10 scale for threat likelihood. The risk model also generates a “delta” risk score which is simply the P90 minus the P50 score to show how much a lack of data drives the risk in the pipeline segment. Currently the Company is utilizing P90 risk for program sub-prioritization. Colorado DIMP and TIMP model P90 risk scores are summarized below based on number and length (feet) of segments:

Table 4 – DIMP Risk Scores by Number and Length of Segment

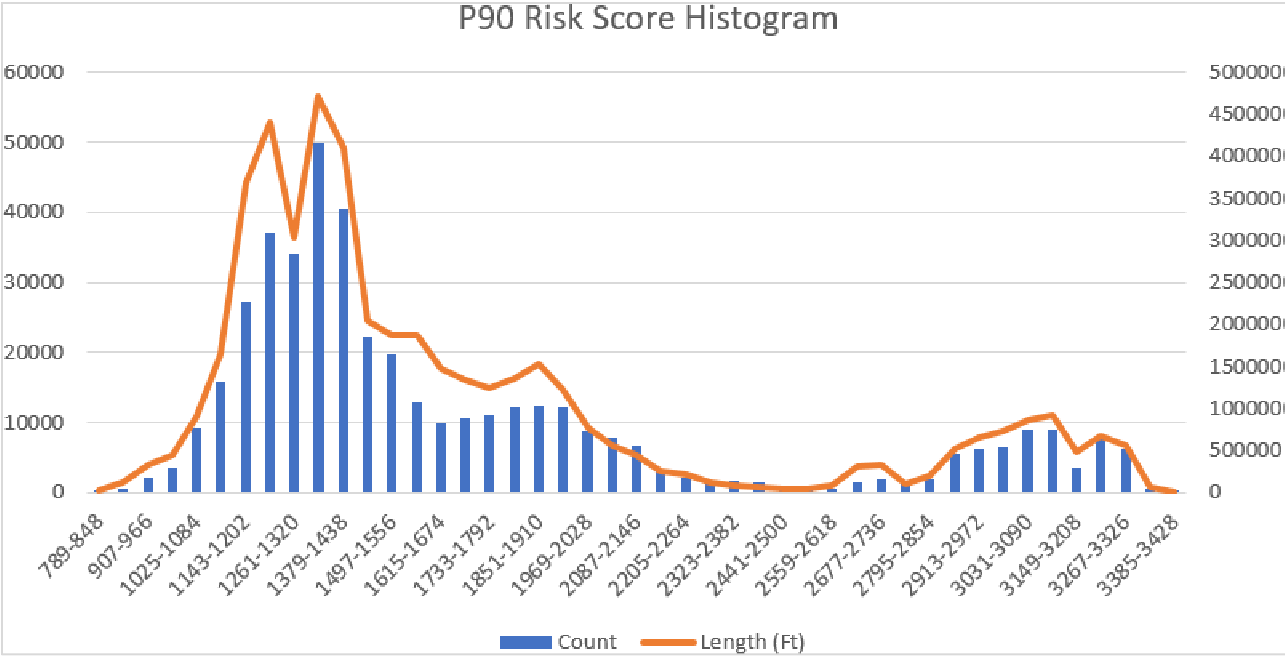
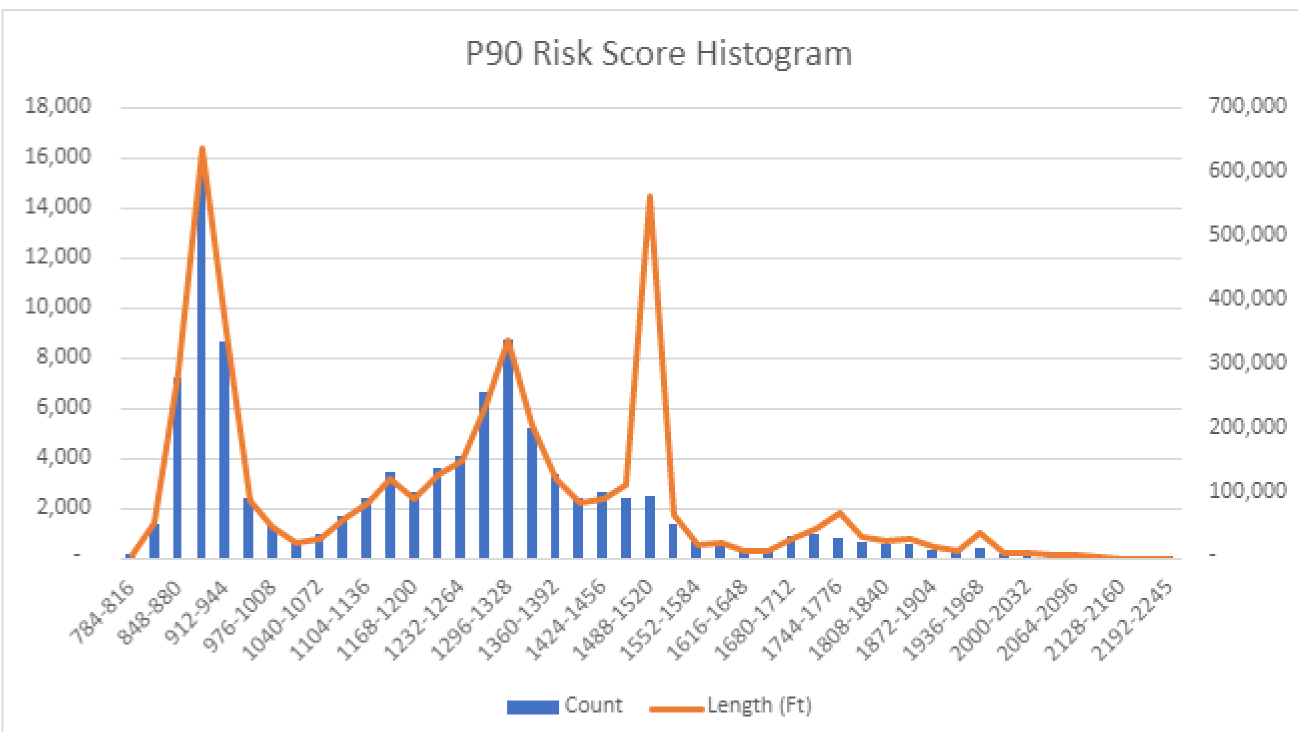


Table 5 – TIMP Risk Scores by Number and Length of Segment



IV. PROJECT IDENTIFICATION PROCESS

The project identification process involves coordination of SMEs from the engineering department, regulatory & finance and operations teams. The approach includes the gathering of specific data for the natural gas system, inputting the data into the risk model, and subsequently taking those inputs and applying the risk score to pipeline segments. Once this step is complete, the appropriate teams meet to review the analysis. These meetings occur on an annual basis and focus on the specific risks and concerns associated with the natural gas system.

While engineering department SMEs are essential to the modeling of known risk, operations SMEs provide vital input based on first-hand knowledge that is necessary to accurately evaluate risk results. Regulatory and finance SMEs provide input on the capital forecasts and regulatory considerations. The outcome of this approach is to jointly determine the appropriate timing of pipeline segment replacement or maintenance. The safety and integrity projects identified through this analysis are then reviewed with other gas infrastructure projects (i.e. Growth, Reliability, or General Plant projects) and then added to the Company's capital forecast.

V. SYSTEM SAFETY AND INTEGRITY RIDER ("SSIR")

BHCG submitted an application with the Colorado Public Utilities Commission ("Commission") in Proceeding No. 20A-0379G in which the Company requested recovery of certain safety and integrity investments through a regulatory rider mechanism known as the SSIR. In Decision No. C21-0397, as amended by Decision No. C21-0517 ("Decision"), the Commission granted the Company approval of the SSIR with certain limitations. The Decision granted approval for SSIR recovery of project costs associated with specific programs of the Company's DIMP and TIMP, as denoted with an (x) in Table 1 above, the Data Infrastructure Improvement Program, and Other SSIR Programs. To be eligible for SSIR recovery, project costs are limited to projects that address high or medium risks in which a numerically calculated relative risk score defines high or medium risk projects based on a predefined system wide risk scale.

Investments associated with the Company's Data Infrastructure Improvement Program ("DIIP") include:

1. Geographic Information Systems ("GIS") and other mapping software improvement initiatives;
2. Filling in missing data gaps (gathering, scanning and indexing historical paper records) including original construction records and maintenance records;
3. Completing the mapping system (validating and verifying data); and

4. Collecting data related to the Customer Owned Yard Lines.

Investments associated with "Other SSIR Programs" are in accordance with interim and final rules and regulations, advisories or directives of the U.S. DOT's PHMSA and other state and federal agencies that have jurisdiction over the Company's pipeline system safety and integrity.

Finally, the Decision granted approval for recovery of these safety and integrity projects through the SSIR in certain geographical areas, excluding Base Rate Area 1 investments.

VI. OVERVIEW OF SSIR PROGRAMS

A. Introduction

The Company's SSIR provides for the recovery of Eligible SSIR Costs incurred for SSIR Projects in accordance with the Company's Colo. PUC No. 1 Tariff Sheet Nos. 54-58.

- Distribution Integrity Management Plan;
- Transmission Integrity Management Plan;
- Data Infrastructure Improvement Program; and
- Other SSIR Programs.

BHCG's integrity programs are driven by their respective DIMP and TIMP. In developing the DIMP and TIMP, the Company utilizes data resulting from the DIIP to better understand organizational needs.

The detailed project summaries are provided in confidential format to protect details regarding the location of critical energy infrastructure and the detailed breakdown of the estimated costs. Along with the attachments previously listed, BHCG presents the following information and supporting data related to the 2023 SSIR Projects.

B. DIMP Programs

1. Thin-Walled Tubing

Program Summary

The thin-walled tubing program is dedicated to replacing tubing that has been discovered to have thinning walls as the pipe ages. Thin-walled tubing generally has a wall thickness of 0.125" and typically utilized grade B materials during installation. Thin-walled tubing is a particular threat due to the manufacturing technique creating a seam along the pipeline. Attempting to repair thin-walled tubing is difficult as welding causes the seam to split back on the pipe.

2023 Planned Activities

There are currently no Thin-Walled Tubing Program projects scheduled for 2023.

Five-Year Plan

While approved for inclusion in the SSIR, based on currently available information, there is are no planned thin-walled tubing projects in the five-year plan. All known thin-walled tubing was replaced in 2022.

Code Reference

There is no specific language tied to thin-walled tubing in Title 49 of Code of Federal Regulations ("CFR"). However, this program falls in line with Title 49, Part 192 Section 1007 of required elements of an integrity management plan. Specifically, section 1007(b) calls for operators to identify threats, and section 1007(d) requires implementation of measures to address these risks.[1]

2. Thin-Walled Steel

Program Summary

The thin-walled steel program is dedicated to replacing tubing that has been discovered to have thinning walls as the pipe ages. Thin-walled steel generally has a wall thickness of 0.125" and typically utilized grade B materials during installation. Due to the thinness of the thin-walled steel, repair work is difficult and may lead to future leaks or failures.

2023 Planned Activities

In 2023, the Company will conduct one project in which approximately 120,000 feet of thin- walled steel will be replaced in Ordway, Crowley, Rocky Ford, and La Junta, Colorado. Refer to the 2023 Project summaries section for project specific details.

[1] See 49 C.F.R. §§192.1007(b) and 192.1007(d).

Five Year Plan

Based on current pipeline information, the Company has identified approximately 44 miles of thin-walled steel on the system that it intends to replace. While the amount of identified thin-walled steel won't be replaced during the duration of the approved SSIR term, the Company plans to replace thin-walled steel each year of the approved SSIR term to remediate the highest priority thin-walled steel.

Much of the identified thin-walled steel on the system is located in Base Rate Area 2 in Rocky Ford, La Junta, and Ordway. Each of these towns have a significant amount of thin-walled steel that will take multiple years to replace.

See Attachment C.1 which provides a preliminary list of projects and forecasted capital costs for the Five-Year Plan. Table 6 below displays the feet of thin-walled steel to be replaced by town and by year between 2023-2027.

Table 6 – Thin-Walled Steel Mitigation

Code Reference

There is no specific language tied to thin-walled tubing in Title 49 of Code of Federal Regulations ("CFR"). However, this program falls in line with Title 49, Part 192 Section 1007 of required elements of an integrity management plan. Specifically, Section 1007(b) calls for operators to identify threats, and section 1007(d) requires implementation of measures to address these risks.[2]

[2] See 49 C.F.R. §§192.1007(b) and 192.1007(d).

3. Regulator Station Barricades

Program Summary

The regulator station barricade program is intended to protect above ground regulators susceptible to outside force damage through the installation of barricades. These regulator stations did not previously have barricades installed to protect them. This threat is largely caused by regulators being set at the customer's property line, in an alley, or adjacent to the street. In addition, the widening of streets and highways, increased utilization of agricultural land, and increased traffic from both farm equipment and motor vehicles have rendered many regulator stations more vulnerable to outside force damage.

Gas system pressure regulators and valve sets are susceptible to outside force damage both in city limits and rural areas. The occurrence of such damage has increased over the years, and records show that the greatest risk to the Company's distribution system is outside force damage, much of which is a result of similar facilities being hit by vehicles and farm equipment. The Company's DIMP identified the need for barricades to prevent damage to these higher risk assets.

2023 Planned Activities

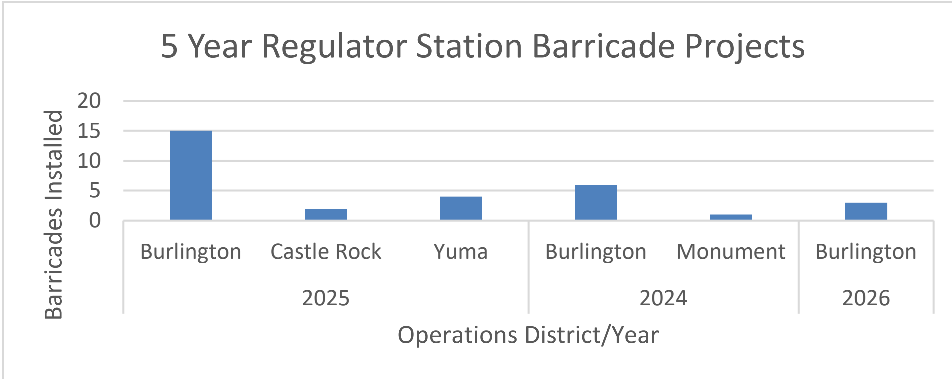
There are currently no Regulatory Station Barricade projects scheduled for 2023.

Five-Year Plan

Based on current information, the Company has identified approximately 31 regulator stations on the system which need barricades to protect them from outside damage. While the number of regulator stations that require barricades installed will not be completed over the approved SSIR term, the Company plans to install regulator station barricades each year of the approved SSIR term to remediate the highest priority regulator stations.

See Attachment C.1 which provides a preliminary list of projects and forecasted capital costs for the Five-Year Plan. Table 7 below displays the number of regulator stations barricades to be installed by town and by year between 2023-2027, as applicable.

Table 7 – Regulator Station Barricade Mitigation



Code Reference

Title CFR 49, Part 192, Section 317(b) notes that "Each above ground transmission line or main, not located offshore or in inland navigable water areas, must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades." The Company asserts that there are similar threats to any above ground distribution asset and is taking a similar approach to mitigate risk.

4. Vintage TBS/DRS Equipment Replacement

Program Summary

This program is intended to replace older equipment on pressure regulation stations. The older equipment is no longer manufactured, replacement parts are not available, and the pressure regulation system is no longer up to current safety design standards. Equipment failure could result in over pressurization and loss of service to customers located downstream of the failure.

2023 Planned Activities

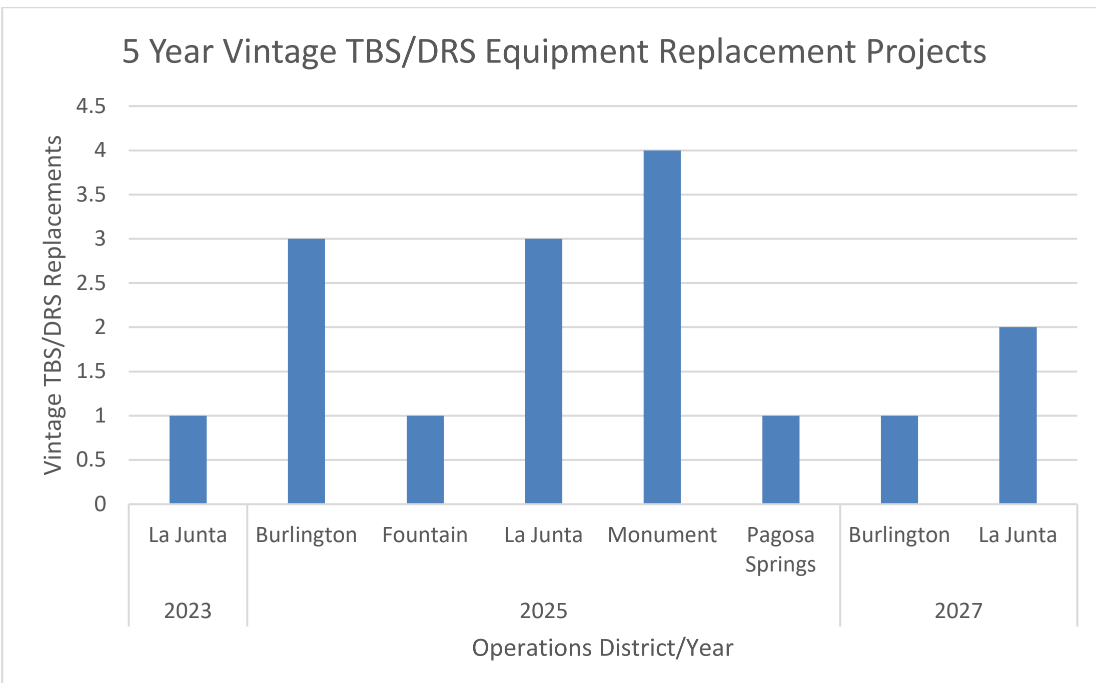
In 2023, the Company will conduct five Vintage TBS/DRS Equipment Replacement projects, most of which are located in Base Rate Area 3. The Company will update one vintage TBS/DRS in the La Junta operations district area, one vintage TBS/DRS in the Fountain operations district area, four vintage TBS/DRS's in the Monument operations district area, three vintage TBS/DRS's in the Castle Rock operations district, and nine vintage TBS/DRS's in the Burlington operations district. See 2023 Project summaries for project specific details.

Five Year Plan

The Company has identified approximately 16
vintage TBS/DRS stations that are planned to be upgraded in the next five years. While the number of identified vintage TBS/DRS stations that need an upgrade will not be fully completed during the initial term of the SSIR, the Company plans to replace vintage TBS/DRS stations in 2023 to be included in the SSIR, , while completing all other identified vintage TBS/DRS stations in 2025 and 2027.

See Attachment C.1 which provides a preliminary list of projects and forecasted capital costs for the Five-Year Plan. Table 8 below displays the number of vintage TBS/DRS stations to be upgraded by operations district and by year between 2023-2027, as applicable.

Table 8 – Vintage TBS/DRS Mitigation



Code Reference

There is no specific language tied to vintage or obsolete regulators in Title 49 of Code of Federal Regulations ("CFR"). However, this program falls in line with Title 49, Part 192 Section 1007 of required elements of an integrity management plan. Specifically, Section 1007(b) calls for operators to identify threats, and section 1007(d) requires implementation of measures to address these risks.[3]

5. Span and Exposed Pipe Replacement

Program Summary

The program is intended to replace high priority spans or exposed segments of pipeline that are currently on the system. These spans or exposed segments may cross a known obstacle, such as a river or drainage ditch, or are exposed due to time dependent factors, such as erosion.

Spans are segments of pipe that were intentionally installed above grade and that cross a known obstacle, which can include creeks, rivers, ditches or highways. These pipes may be supported or unsupported. Supported spans can be attached to a bridge or similar structure, while unsupported spans are generally shorter segments of pipe that are not supported by any structures and are freestanding. Exposed pipes are those that were originally installed below grade. While they were intended to remain below grade, time dependent factors have impacted cover. Erosion and other outside forces have unearthed these pipes that should remain below grade.

Span pipelines are a higher risk asset because of external corrosion factors, risk of movement in the structure to which they are attached, external forces and natural forces. Spans are generally comprised of steel, a material that degrades over time due to atmospheric corrosion. Additionally, spans can be attached to structures that have decayed over time and are no longer structurally sound. Whenever possible, when replacing these pipelines, the Company will remove these pipelines from the structure. If a pipeline cannot be removed from the structure, the types of connectors utilized to attach the pipeline to the structure will be modified based on technological improvements. External and natural forces increase the likelihood of damage to spans. These forces can include vehicle strikes, rockslide, structure maintenance, road treatments, including magnesium chloride, surface erosion, lightning, storms, wind, earthquakes, and flooding.

[3] See 49 C.F.R. §§192.1007(b) and 192.1007(d).

Exposed pipelines are also at increased risk because of external corrosion factors, external forces, and natural forces described previously. These pipelines are not impacted by the structural risks that impact spans. However, exposed pipelines face increased risks associated with external corrosion, being washed out, impacted by debris and by human contact.

2023 Planned Activities

There are no planned Spanned and Exposed Pipe Replacement projects in 2023.

Five Year Plan

At the current time, there are no planned Spanned and Exposed Pipe Replacement projects in the Five-Year Plan as the Company has chosen to allocate resources to other higher priority projects in the coming years.

Code Reference

Title CFR 49, Part 192, Section 317(a) notes that "The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads." The Company asserts that there are similar threats to any above ground distribution asset and is taking a similar approach to mitigate risk.

6. Bare Steel – Protected

Program Summary

This program is intended to replace bare steel pipe that is cathodically protected. The installation of bare steel pipe was popular in the 1950s and is no longer an acceptable construction practice. Even though these bare steel distribution mains are cathodically protected, they are susceptible to corrosion because they are not coated to resist corrosion. Additionally, it becomes increasingly difficult to maintain effective corrosion protection due to the age of the system. Compared with coated steel pipelines, bare steel pipelines corrode at a higher rate because there is no coating to serve as a barrier between the steel and soil.

2023 Planned Activities

There are no planned Bare Steel – Protected program projects in 2023.

Five-Year Plan

At the current time, there are no planned Bare Steel – Protected program projects in the Five-Year Plan as the Company has chosen to allocate resources to other higher priority projects in the coming years.

Code Reference

There is no specific language tied to cathodically protected bare steel in Title 49 of Code of Federal Regulations ("CFR"). However, this program falls in line with Title 49, Part 192 Section 1007 of required elements of an integrity management plan. Specifically, Section 1007(b) calls for operators to identify threats, and section 1007(d) requires implementation of measures to address these risks.[4] As noted by PHMSA, "[t]he age and lack of protective coating typically makes bare steel pipelines of higher risk as compared to other pipelines and candidates for accelerated replacement programs."[5]

[4] See 49 C.F.R. §§192.1007(b) and 192.1007(d).

[5] https://www.phmsa.dot.gov/data-and-statistics/pipeline-replacement/pipeline-replacement-background

7. Poorly Coated Steel

Program Summary

This program is intended to replace poorly coated steel pipe on the Company's system. Poorly coated steel, similar to bare steel pipe, was popular in the 1950s and is no longer an acceptable construction practice. Poorly coated steel has no cathodic protection, but is coated. This poorly coated steel was installed with coating, however it is ineffective based on today's accepted construction practices. Degradation of this poorly coated steel could result in failure that causes customers to lose service in various and areas across the state for extended periods of time. Poorly coated steel tends to develop coating issues where pipe is mechanically coupled, pipe is girth welded using acetylene, or the pipe is more than 50 years old. The Poorly Coated Steel Program is broadly defined by the Company as Vintage Steel replacement.

2023 Planned Activities

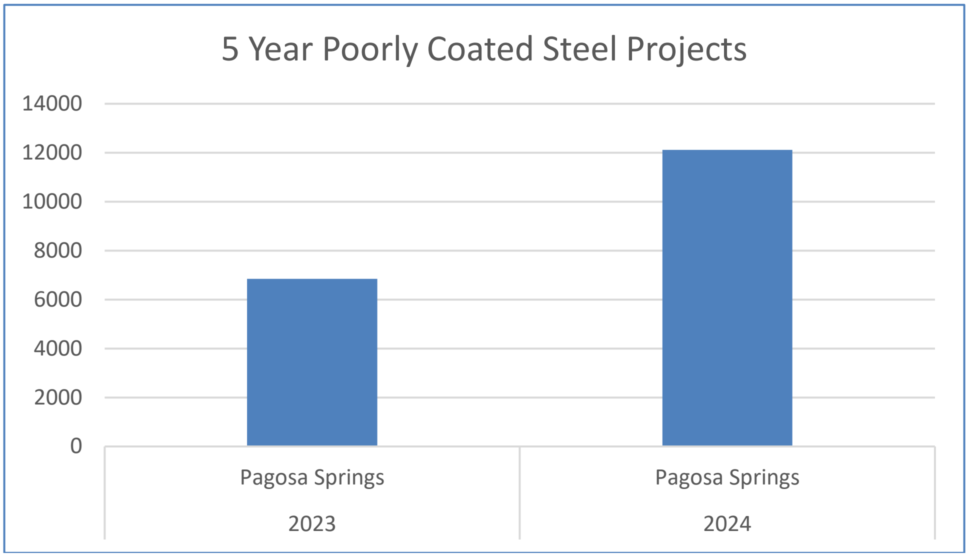
In 2023, the Company will conduct one Poorly Coated Steel project in Pagosa Springs, Colorado. This project will replace approximately 6,850 feet of poorly coated steel. Refer to the 2023 Project summaries section for project specific details.

Five Year Plan

The Company has identified approximately 19,000' of Poorly Coated Steel pipeline that needs replacement. As currently planned, the Company anticipates replacing all identified poorly coated steel by 2024, with projects conducted in the Pagosa Springs operations district each year of the approved SSIR term. All poorly coated steel project costs are planned for recovery through the SSIR.

See Attachment C.1 which provides a preliminary list of projects and forecasted capital costs for the Five-Year Plan. Table 9 displays the feet of poorly coated steel to be replaced by town and by year in 2023 and 2024.

Table 9 – Poorly Coated Steel Mitigation



Code Reference

There is no specific language tied to poorly coated steel in Title 49 of Code of Federal Regulations ("CFR"). However, this program falls in line with Title 49, Part 192 Section 1007 of required elements of an integrity management plan. Specifically, Section 1007(b) calls for operators to identify threats, and section 1007(d) requires implementation of measures to address these risks.[6]

[6] See 49 C.F.R. §§192.1007(b) and 192.1007(d).

C. TIMP Programs

1. Vintage Pipe

Program Summary

Although age alone does not determine the integrity of a pipeline system, some older pipeline facilities that are made of certain materials and with certain coatings may have degraded over time. Even though transmission lines are cathodically protected, it becomes increasingly difficult to maintain effective corrosion protection because of the age of the system. This program focuses on the replacement of vintage transmission lines with issues identified in the corrosion prevention coating, construction standards, and materials used. Asset replacements within this program will be identified as pre-1972 when the federal pipeline safety standards were largely implemented. Based upon known data, including installation records and construction methods, leakage history, cathodic protection data, damage history and population density, the TIMP identified the relative risk of transmission pipeline segments.

2023 Planned Activities

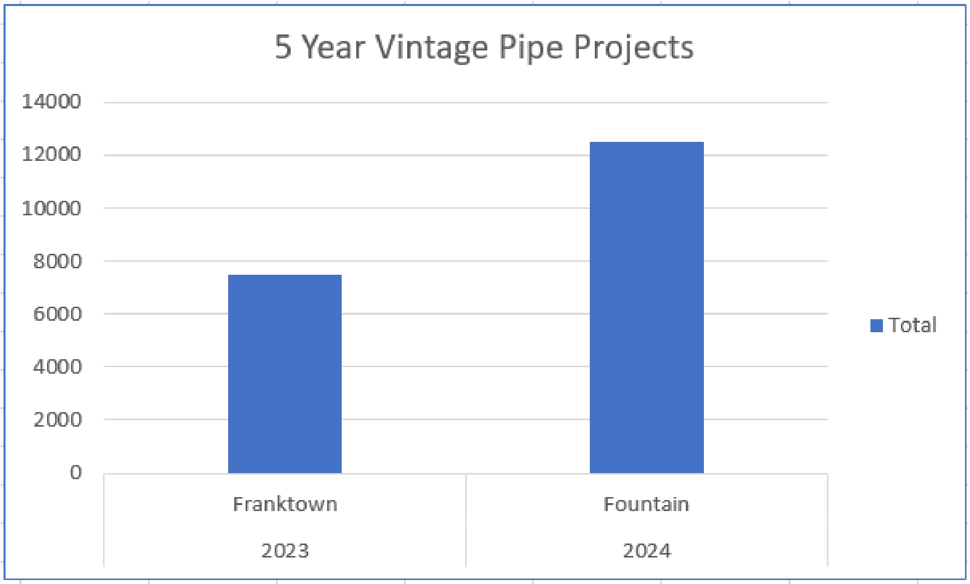
In 2023, the Company will conduct one Vintage Pipe project in Franktown, Colorado. This project will replace approximately 7,500 feet of vintage transmission steel in Franktown. Refer to the 2023 Project summaries section for project specific details.

Five Year Plan

The Company has identified approximately 20,000 feet of vintage transmission pipe to be replaced. As currently planned, the Company anticipates replacing all identified vintage transmission pipe by 2024, to be completed within the term of the SSIR.

See Attachment C.1 which provides a preliminary list of projects and forecasted capital costs for the Five-Year Plan. Table 10 displays the feet of vintage pipe to be replaced by town and by year in 2023 and 2024.

Table 10 – Vintage Pipe Mitigation



Code Reference

There is no specific language tied to vintage pipeline in Title 49 of Code of Federal Regulations ("CFR") Part 192. However, this program falls in line with 192.1007 of required elements of an integrity management plan. 192.1007(b) calls for operators to identify threats, and subpart (d) requires implementation of measures to address these risks.[7]

D. DIIP Programs

1. Data Initiative

Program Summary

The DIIP is intended to improve the knowledge of the Company pipeline system to provide BHCG with the ability to positively confirm the integrity of the pipeline system. There continues to be a knowledge gap with respect to the pipeline system. The DIIP will implement specific initiatives to improve system data, including data gap elimination, GIS updates, programmatic improvements, and the continued roll-out of Digital As-Built technology in Colorado.

In order to continuously improve pipeline risk ranking for purposes of prioritizing accelerated threat mitigation efforts, it is vital for the Company to be able to identify risks,

[7] See 49 C.F.R. §§192.1007(b) and 192.1007(d).

understand the consequence of those risks, develop GIS tools, close known data gaps, and continuously improve system knowledge. The DIIP will close known data gaps, develop and improve GIS tools, and verify current data for accuracy.

The DIIP syncs various Company databases to evaluate information that is missing with respect to main and service line locations, materials, diameter, cathodic protection, air pressure test, Maximum Allowable Operating Pressure, and asset condition.

2023 Planned Activities

In 2023, the Company will conduct one Data Infrastructure Improvement Program projects. Refer to the 2023 Project summaries section for project specific details.

Five Year Plan

At the current time, the Company has plans for DIIP projects each year of the SSIR term through 2024.

See Attachment C.1 which provides a preliminary list of projects and forecasted capital costs for the Five-Year Plan.

Code Reference

This program falls in line with the requirements in Title 49 of Code of Federal Regulations ("CFR") Part 192. Specifically, 49 C.F.R. § 192.1007 requires operators to demonstrate an understanding of their gas assets and identify threats to those assets.

E. Summary of SSIR Programs Costs

Table 11 below represents a summary of the forecasted capital costs for 2023 SSIR Projects. The proposed SSIR revenue requirement calculation for these projects and prior year SSIR projects is detailed on Attachment D – 2023 SSIR Revenue Requirement to Advice Letter No. 25.

Table 11 – Total 2023 SSIR Project Costs by Rate Area and Program

Base Rate Area	Integrity Management Plan	Programs	2023 SSIR Capital Costs
RA 2	DIMP	Thin-Walled Steel	$8,245,675
		Vintage TBS/DRS Equipment Replacement	$526,213
		Poorly Coated Steel	$2,400,435
	DIIP	Data Initiative	$325,645
RA 3	TIMP	Vintage Pipe	$2,439,500
	DIIP	Data Initiative	$1,265,628
		TOTAL 2023 SSIR Project Costs	**$15,203,096**

Table 12 below summarizes the forecasted capital costs for the Company's 2023-2027 Five Year SSIR Plan by program.

Table 12 – 2023-2027 SSIR Forecasted Costs ($ in millions)[8]

	2023	2024	2025	2026	2027	Total
DIMP						
Thin-Walled Steel	$ 8,245,675	$ 1,776,986	$ 5,148,173	$ 2,174,277	$ -	**$ 17,345,112**
Vintage TBS/DRS Equipment Replacement	$ 526,213	$ -	$ 1,545,429	$ -	$ 1,604,115	**$ 3,675,757**
Poorly Coated Steel	$ 2,400,435	$ 4,689,853	$ -	$ -	$ -	**$ 7,090,288**
Regulator Station Barricade	$ -	$ 154,350	$ 416,745	$ 72,930	$ -	**$ 644,025**
TIMP						
Vintage Pipe	$ 2,439,500	$ 7,166,250	$ -	$ -	$ -	**$ 9,605,750**
DIIP						
Data Initiative	$ 1,591,273	$ 3,680,024	$ -	$ -	$ -	**$ 5,271,297**
Total SSIR Budget 2023-2027	**$ 15,203,096**	**$ 17,467,463**	**$ 7,110,347**	**$ 2,247,208**	**$ 1,604,115**	**$ 43,632,229**

[8] Table may not foot due to rounding