PUBLIC SERVICE COMPANY OF COLORADO

ANNUAL PIPELINE SYSTEM INTEGRITY

ADJUSTMENT REPORT

2020 ACTUALS

PROCEEDING NO. 19AL-0643G

April 1, 2021

CONTENTS

ATTACHMENTS

I. Overview

Public Service Company of Colorado's ("Public Service" or the "Company") Pipeline System Integrity Adjustment ("PSIA") Colo. PUC 6 – Gas tariff Sheet No. 47 filed in Proceeding No. 19AL-0643G provided for the recovery of costs incurred pursuant to the following four integrity management programs and projects:

- Accelerated Main Replacement Program ("AMRP");
- Distribution Integrity Management Program ("DIMP");
- Transmission Integrity Management Program ("TIMP"); and
- West Main Replacement Project.[1]

The Company must file with the Colorado Public Utilities Commission ("Commission") annually, on or around April 1, a report explaining the activities the Company undertook pursuant to its PSIA-eligible initiatives during the preceding calendar year, how costs incurred for these activities are managed, and any deviations between budgeted and actual costs. The contents of this 2020 PSIA Actuals Report ("2020 PSIA Actuals Report") are intended to be in compliance with all of the requirements applicable to the Company's PSIA annual reports as adopted by the Commission in Decision No. R14-0694 (mailed June 25, 2014) in Proceeding No. 13M-915G; and Decision No. R140736 (mailed July 1, 2014) in Proceeding No. 10AL-963G, as modified by Decision Nos. C16-0123 (mailed February 16, 2016) and R15-1204 (mailed November 16, 2015), respectively, in Proceeding No. 15AL-0135G; Decision No. R19-0696 (mailed August 20, 2019) in Proceeding No. 17AL-0771G; and Decision No. C18-0983 (mailed November 6, 2018), in Proceeding No. 18A-0422G.

The following narrative provides:

- an explanation of the PSIA revenue requirement calculation and drivers of the $6.2 million decrease between the actual net revenue requirement in this filing for the period of January 1, 2020 through December 31, 2020, as compared to the estimate provided in the November 2019 PSIA filing (Proceeding No. 19AL-0643G).
- a high-level explanation of how the Company prioritized projects and managed risks during 2020;
- an explanation of how the projects and associated costs correlate with the elements that are consistent with federal regulations; and

[1] The West Main Replacement Project is not one of the 11 specifically-identified Projects under DIMP or TIMP for which additional capital spending is eligible in 2019-2021 under the approved Settlement Agreement. Thus, there were no actual 2020 West Main Replacement Project capital expenditures.

- a comparison of actual 2020 activities and costs to estimated activities and costs provided in the November 2019 PSIA filing, for each of the programs and projects described above.[2]

The Company's attachments provide detailed support for the actual capital expenditures incurred during 2020 in connection with the integrity management programs and projects. In addition, as required by Decision No. R19-0696 in Proceeding No. 17AL-0771G, the Company is providing with this report a "2020 Actuals Rollforward" document included as Attachment 8 that demonstrates the path through which 2020 PSIA capital expenditures became plant additions. Due to the depreciation rates changing on November 1, 2020, Attachment 8 contains two rollforwards to reflect the change.

In 2020, the Company's actual net revenue requirement was about 5.6% lower than the forecast provided in the November 2019 PSIA filing. The level of variance differed for each of the programs as shown in the Tables II-1 through II-3 below.

A variety of factors contributed to the variance between the November 2019 PSIA filing of projected costs of capital and actuals, including:

- differences between the forecasted and actual plant balances at the end of 2020;
- differences between the forecasted and actual capital expenditures in 2020;
- differences between the forecasted and actual closing patterns of plant in-service for both 2020 capital expenditures and capital expenditures incurred before 2020 that were placed in-service in 2020;
- differences between the forecasted and actual mix of assets placed in-service in 2020 (e.g., the percentage of assets added with relatively short or relatively long service lives);
- differences between forecasted and actual tax depreciation (e.g., bonus depreciation allowances), affecting rate base in conjunction with changes to net plant;
- differences between forecasted and actual rate of main renewals; and
- differences between forecasted and actual weighted average cost of capital.

[2] Attachment 7 to this Report also contains a reference to which report a project first appeared in, as the Company committed to do in the "Notice of Resolution of Disputed Issues and Motion to Vacate Remaining Deadlines and Prehearing Conference" filed in Proceeding No. 17AL-0771G on August 12, 2019.

II. PSIA Revenue Requirement

The 2020 actual PSIA annual revenue requirement is $98,828,142 compared to the 2020 forecast PSIA annual revenue requirement of $104,993,028.[3] This resulted in a reduction in the annual revenue requirement of $6,164,886.

As pertinent to the revenue requirement presented herein, on February 5, 2020, the Company filed a combined Phase I and Phase II rate case in Proceeding No. 20AL-0049G ("2020 Gas Rate Case"). The case was resolved through an approved Unopposed and Comprehensive Amended Stipulation and Settlement Agreement ("2020 Gas Rate Case Settlement"), which contained several provisions affecting the PSIA, as well as this particular filing. *See* Decision No. R20-0673.- With respect to this filing, the 2020 Gas Rate Case Settlement provides:[4]

> 3. The Settling Parties further recognize that the changes to the WACC identified in this Settlement Agreement will also need to be applied to the PSIA at the time Settled Rates take effect in November 2020. Any true-up to the 2020 PSIA from the November rate-effective date through the end of 2020 will be captured and implemented in conjunction with the annual PSIA rider true-up process, which, in this instance, will be filed April 1, 2021.

As a result, the 2020 Gas Rate Case Settlement further required the following: "[o]n April 1, 2021 the Company will file its annual PSIA true-up filing and incorporate into that filing any amounts owed for the change in WACC applicable to the PSIA between the Rate Effective Date and December 31, 2020."[5]

The terms of the 2020 Gas Rate Case Settlement that applied to this PSIA filing were implemented by calculating two PSIA revenue requirements. Both revenue requirements utilized the same set of projects. The difference between the two revenue requirement calculations is in the ROE used in the calculation and the depreciation rates applied to the projects included in the revenue requirement. The first revenue requirement used a 9.35% ROE and the depreciation rates that were in effect on January 1, 2020. The second revenue requirement calculation used a 9.2% ROE and the depreciation rates that were approved in the 2020 Gas Rate Case. For the purposes of calculating the true up amount, the two revenue requirements were averaged together based on the number of months the ROE and depreciation rates were in effect. The revenue requirement based on the 9.35% ROE was weighted by ten twelfths and the revenue requirement based on the 9.2% ROE was weighted two twelfths. Both revenue requirement calculations and the weighting are provided in Attachment 2.

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[3] In the process of preparing this report the Company identified a work order for DIMP Shorted Casings in the amount of $21,203 that was determined to not be shorted after initial work had begun. This will be adjusted out of the Revenue Requirement prior to inclusion in the November Filing. The estimated impact on the revenue requirement is approximately $1,500.

[4] 2020 Gas Rate Case Settlement at Section III.D.3.

[5] 2020 Gas Rate Case Settlement at Section III.R.3. See also Decision No. R20-0673 at ¶56.

The significant drivers of the approximately $6.2 million decrease in the annual revenue requirement includes the following:

- The AMRP revenue requirement decreased approximately $1.4 million primarily due to actual plant in-service decreasing $9.8 million from forecast. Plant in-service decreased due to timing of project in-servicing. The decrease was also driven by a decline in the cost of debt and the lower ROE which was effective on November 1. Additional details on project level cost variances are provided in the Project Summary, Attachment 1 and in the Detailed Variance Explanations, Attachment 7.

- The DIMP revenue requirement decreased approximately $2.67 million, primarily due to actual plant in-service decreasing $18.6 million from forecast. Plant in-service decreased due to lower than estimated expenditures resulting from risk mitigation efficiency where projects were completed below estimate. The decrease was also driven by a decline in the cost of debt and the lower ROE which was effective on November 1. Additional details on project level cost variances are provided in the Project Summary, Attachment 1 and in the Detailed Variance Explanations, Attachment 7.

- The TIMP revenue requirement decreased approximately $2 million primarily due to actual plant in-service decreasing $14 million. Plant in-service decreased due to lower capital expenditures, primarily due to completion of projects under budget and delayed in-service. The decrease was also driven by a decline in the cost of debt and the lower ROE which was effective on November 1. Additional details on project level cost variances are provided in the Project Summary, Attachment 1 and in the Detailed Variance Explanations, Attachment 7.

- The West Main Replacement revenue requirement decreased approximately $134 thousand, due to the decline in the cost of debt and the lower ROE which was effective on November 1.

The primary drivers listed above are not a comprehensive list of the drivers between estimated and actual activities and costs. The following tables itemize the variations between actual and estimated capital expenditures, additions to plant in-service, and total revenue requirement by program or project.

Table II-1: 2020 Capital Expenditures Estimate Versus Actual (All $ Values in Millions)

	2020 Estimate As Filed	2020 Actual	Difference	Percent
AMRP	$39.8	$45.8	$6.1	15.2%
DIMP	$53.1*	$51.0*	($2.1)	(4.0%)
TIMP	$74.0	$63.6	($10.4)	(14.0%)
Total	**$167.0**	**$160.4**	**($6.5)**	**(3.9%)**

Note: Total, Difference and Percent calculations were performed at $000's.
* Base amount related to Leadville included in totals above, but not recovered through the PSIA Rider.

Table II-2: 2020 Retail Plant In-Service Estimate Versus Actual (13-Mo Avg in Millions)

	2020 Estimate As Filed	2020 Actual	Difference	Percent
AMRP	$292.82	$282.94	($9.88)	(3.37%)
DIMP	$376.90	$358.31	($18.59)	(4.93%)
TIMP	$421.90	$407.80	($14.10)	(3.34%)
West Main	$138.98	$138.96	($0.02)	(0.01%)
Total	**$1,230.60**	**$1,188.01**	**($42.59)**	**(3.46%)**

Note: Total, Difference and Percent calculations were performed at $000's.

Table II-3: 2020 Capital Revenue Requirement

	2020 Estimate As Filed	2020 Actual	Difference	Percent
AMRP	$26.09	$24.67	($1.42)	(5.44%)
DIMP	$36.32	$33.65	($2.67)	(7.35%)
TIMP	$35.71	$33.78	($1.93)	(5.40%)
West Main	$11.11	$10.98	($0.13)	(1.17%)
Total	**$109.23**	**$103.08**	**($6.15)**	**(5.63%)**

Note: Total, Difference and Percent calculations were performed at $000's.

Section IV of this narrative provides more detailed explanations of these itemized changes by program or project.

III. Prioritizing Projects and Managing Risks

The goal of any pipeline integrity program is to ensure the safety of the system in a cost-effective manner. This goal can be best achieved by following the directives contained in the Code of Federal Regulations ("Federal Code" or "CFR") for TIMP and DIMP and by continuously improving knowledge of gas system assets to understand the risks posed by various threats and then remediate those threats. Managing risk, which is the principle objective of an integrity management program, is not pursued in a strictly sequential manner, as the Company can and should engage in significant remediation efforts at the same time as data is gathered and threats against Company assets are being understood.

The Company effectively prioritizes integrity work (and effectively adjust plans to address changing circumstances and the incorporation of new information) based on the various risks to the system. Additionally, the Company stays abreast of proposed or final rulemakings from the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") to understand new requirements and determine how they impact program management and subsequent prioritization of work.

For example, in March of 2016, PHMSA issued a Notice of Proposed Rulemaking ("NPRM") under Docket No. PHMSA-2011-0023. This NPRM proposed to revise the Pipeline Safety Regulations applicable to the safety of onshore gas transmission and gathering pipelines. PHMSA proposed changes to the integrity management ("IM") requirements as well as changes to non-IM requirements. The original NPRM was published as one rule in 2016 and was later split into three separate rules. The first of the three rules, PHMSA's Safety of Gas Transmission Pipelines Final Rule (Docket No. PHMSA–2011–0023), was published on October 1, 2019 with an effective date of July 1, 2020 (extended to December 31, 2020 due to impacts of COVID-19).

The specific IM requirement changes from the first rule include:

- expansion of IM beyond High Consequence Areas ("HCAs");
- establishment of moderate consequence areas ("MCAs");
- maximum Allowable Operating Pressure ("MAOP") validation and reconfirmation;
- record retention; and
- materials verification requirements.

The second rule is anticipated to become final in early 2021 and is expected to include significant impacts to anomaly repair criteria, inspection after extreme events, and expanded corrosion control programs. The third rule is also expected in 2021 and will expand safety regulations to certain rural gathering lines typically operated by oil and gas producers and processors.

The intent of PHMSA's previous Integrity Verification Process ("IVP") as well as the MAOP validation and reconfirmation portions are to ensure that operators of transmission pipes have adequate records about their assets. In 2020, the Company continued its focus on gathering additional data on pipelines as defined by PHMSA.

In the context of risk evaluation and management, the Company evaluates the options of pressure testing, pressure reduction, and pipeline replacement to remediate pipelines with record gaps. Intrastate transmission systems, like those of the Company, are often the single source of supply to a community or business, and many are directly integrated with distribution systems. In some cases, replacement may be a viable alternative to testing, and may be the only alternative for pipes that cannot be removed from service.

At the same time that the Company is pursuing the collection of system data, information is being collected to further its understanding of the primary threats against the assets through TIMP assessments and additional inspections of distribution assets. Simultaneously, the Company is engaging in efforts to mitigate identified risks through both immediate repairs based on assessments and comprehensive replacement programs for pipe types previously found to impose disproportionately high risks—such as the pipe types targeted by AMRP and PPRP.

In any given year, balancing resources among data collection, targeted assessments, remediation of known threats, and comprehensive replacement programs is a difficult task. The competing demands of multiple initiatives require allocation of resources to maximize value. Practical considerations include minimizing disruptions to communities, minimizing the number of times crews are dispatched to the same geographical area, and the availability of external resources such as contract labor and specialized in-line inspection tools. To that end, the Company furthered its strategy by obtaining multi-year contracts with key vendors to complete work related to these projects. This includes having multiple engineering and construction vendors under contract that can support a diverse project profile across the state.

As explained in more detail in Exhibit 4, Attachment E, to the Company's advice letter filing in Proceeding No. 19AL-0643G, projects are ranked based on their relative risks, as well as their immediate impact on public safety. Any immediate condition is top priority and is addressed to protect public and employee safety. Given the level of risk surrounding several vintage pipe types along with state and federal regulatory scrutiny, a credible pipeline operator must target these pipes for replacement in a systematic manner. The goal of systematically replacing poor-performing pipe types is the focus of two of the integrity programs or projects within this report – the AMRP and PPRP. The Company's proactive and systematic approach of removing poor performing pipes improves the overall safety and reliability of the pipeline network.

TIMP is very prescriptive about certain assessment protocols and how to address certain types of anomalies. The Company is required to assess the health and condition of gas transmission assets on a frequency of not less than every seven years, with priority given to those located in High Consequence Areas ("HCAs"). Assessments are conducted each year on a portion of the gas transmission assets to ensure that the prescribed reassessment intervals are met. In general, HCAs are defined as areas along a pipeline where the consequence of an incident could be severe (e.g., resulting in fatalities, personal injury, and/or property damage). The Federal Code governing TIMP defines which type(s) of assessment methodologies the Company must use in order to evaluate certain risks/threats for those pipeline segments. The Company must respond accordingly (immediately or within a specified timeline) to identified anomalies with certain characteristics. In some cases, the Company can choose when to make a repair (such as when the area is being excavated for other work). Other anomalies must be monitored over time to determine the rate of corrosion growth and need for future action. The total count of anomalies identified to date numbers into the thousands, with the majority being either minor dents due to excavation damage or levels of corrosion that do not pose an immediate risk. The Company continues to monitor these anomalies over time utilizing various assessment methods and repairs will be undertaken before they become a threat to the integrity of the system.

DIMP is not as prescriptive as the TIMP but contains the same basic components of know your assets, understand the risks and threats against those assets, and proactively mitigate the risks and threats. Although distribution systems typically operate at lower pressures, they are typically in densely populated areas. Recent high-profile incidents, such as the September 2018 Columbia Gas explosion and fire incidents in Massachusetts, show that significant events can also occur on these lower pressure systems.

The Company has implemented a risk ranking and prioritization process applicable to pipeline facilities covered by DIMP. While outputs from the computerized model provides the Company with a starting point of understanding system risk from a relative perspective, other information (e.g., maintenance history) also informs prioritization of work. The computerized model also does not accommodate all distribution assets. For the other assets, the Company uses other methods to evaluate risk and prioritize projects. For example, the relative risk assessment and prioritization associated with the protection of above-ground facilities, (e.g., meters and regulator stations) is not performed using the computerized risk model.

Management of risks under the DIMP involves various approaches that are explained in more detail within this report. Some material types such as cast iron, Aldyl-A, and polyvinyl chloride ("PVC") are prone to failure; therefore, replacement of these materials is appropriate. Risk analysis has also revealed that certain segments of vintage steel exhibit very high leak ratios. In general, this material is older and has not been cathodically protected over its entire life.

Managing the integrity and continual safe operation of the Company's gas systems requires continually addressing the required elements of TIMP and DIMP, as well as adherence to internal processes and standards. The progression of risk evaluation, determination of mitigation measures and the prioritization of projects are iterative and continually evolve as new data is obtained. The Company incorporates knowledge gained about assets through normal operations and maintenance activities, pipeline assessments and inspections, proactive preventive and mitigation measures, industry trends and events, and guidance or mandates from regulatory entities.

IV. Details of Programs and Projects Undertaken in 2020

A. Distribution Programs

ACCELERATED MAIN REPLACEMENT PROGRAM

Program Overview:
The AMRP began in 2008 and is a multi-year renewal effort focused on cast iron, bare steel, and PVC mains and the associated services. Cast iron and bare steel are susceptible to the time-dependent threat of corrosion. Furthermore, cast iron can also "graphitize." Cast iron pipe that has experienced the prolonged effects of graphitization simply crumbles apart with the consistency of soil. Conversely, PVC is not exposed to corrosion threats, but has unique material characteristics causing the plastic to become more brittle over time. The increased brittleness of PVC material exposes the pipe to increased risk of brittle-like cracking when the pipe has been disturbed by tree roots or other soil movement, such as frost heave. In addition, aging glue in PVC pipe joints can disbond as it degrades increasing the risk of joint separation.

There are currently no federal requirements that specifically mandate replacement of vintage mains. However, 49 C.F.R. §192.1007(d) requires that operators identify and implement measures to address risks. This project is conducted to address the risks associated with these vintage assets.

Program Scope:
Pressure System:
Cast iron, bare steel, and PVC pipe types that are exclusively within the Company's distribution pipeline system and operate at less than 1 psi up to 66 psi.

Pipe Materials and Vintages Included:
Cast iron and bare steel mains were some of the first pipe types installed in gas distribution systems in the early part of the 20th Century and continued to be installed through the mid-1950s. PVC was primarily installed in the 1960s and 1970s. All known cast iron main in the Company's distribution system was replaced by the end of 2014. Additional cast iron main is occasionally identified during the normal course of business and scheduled for renewal.

Overall Program Status:
Through December 31, 2019, 243 miles out of a targeted 540 miles of distribution main had been completed. In 2020, an additional 29 miles of distribution main were replaced, which brings the program to 50 percent complete based on the targeted 540 miles reflected in the current PSIA. All known cast iron was renewed by the end of 2014.

Key Activities and Costs since November 2019 PSIA filing:
The revenue requirement in the November 2019 PSIA filing were based on the Company's plan to replace 22 miles of pipe in 2020 under AMRP. Table IV-1 and Table IV-2 provide the variances between estimated and actual 2020 AMRP activities and capital expenditures. Table IV-3 provides a unit costs variance assessment.

Table IV-1: 2020 AMRP Construction Activities

Main Type Replaced	2020 Estimate As Filed (miles)	2020 Actual (miles)	Variance
Bare Steel	-	3	3
PVC	22	26	4
Cast Iron	-	-	-
Total	**22**	**29**	**7**

Service Type Replaced	2020 Estimate of Services As Filed (each)	2020 Actual Services (each)	Variance
Bare Steel PVC	1,251	1,018	(233)
Total	**1,251**	**1,018**	**(233)**

Table IV-2: 2020 AMRP Costs
(All $ Values in Millions)

	Capital Expenditures	13-Month Average Plant In-Service	Revenue Requirement
2020 Estimate As Filed	$39.8	$292.82	$26.09
2020 Actual	$45.8	$282.94	$24.67
Variance	$6.1	($9.88)	($1.42)
Percentage Variance	15.2%	(3.37%)	(5.44%)

Table IV-3: 2020 AMRP Unit Cost

		Mains	Services
2020 Estimate As Filed	Miles / # Services	22 miles	1,251
	Cost Per Unit	$1.6 M/mile	$4,300/Service
	Total Expenses	$34. 5 M	$5.4 M
2020 Actual	Miles / # Services	29 miles	1,018
	Cost Per Unit	$1.3 M/mile	$7,075/Service
	Total Expenses	$38.7 M	$7.2 M
Variance	Miles / # Services	7 Miles	(233 Services)
	Variance Per Unit	($0.2 M/mile)	$2,775/Service
	Total Expenses	$4.2 M	$1.8 M

Overall, AMRP replaced seven more miles of mains than anticipated and fewer services than the November 2019 filing estimate. The reduced cost per mile can be attributed to improved project management which produced better planning, risk mitigation, and execution of projects. These efforts included advanced planning for permitting, working with local governments on restoration, and reducing the overall labor costs on projects. As discussed in the third quarter presentation, improved financial forecasting and the completion of 2021 design work well in advance enabled the Company to reach and exceed its planned AMRP budget by approximately six million dollars.

Further, nearly all of the remaining bare steel main segments identified in 2019, were removed in 2020. As of December 31, only two known main segments remained with a combined length of less than 500 feet.

Additional details on project level cost variance are provided in the Project Summary, Attachment 1.

<u>Code Reference:</u>

- 49 C.F.R. § 192.1007(d)
- PHMSA Advisory Bulletin ADB-07-01
  http://www.gpo.gov/fdsys/pkg/FR-2007-09-06/pdf/07-4309.pdf
- PHMSA Advisory Bulletin ADB-08-02
  http://www.gpo.gov/fdsys/pkg/FR-2008-03-04/pdf/E8-4155.pdf
- PHMSA Advisory Bulletin ADB-12-05
  https://www.govinfo.gov/content/pkg/FR-2012-03-23/pdf/2012-7080.pdf

<u>Changes in Pipeline Capacity:</u>

AMRP encompasses many main replacements in established metropolitan areas of Colorado. Generally, projects are like-for-like replacements with little to no impact on capacity. The standard replacement size based on the existing size is shown in Table IV-4 with a description of why some sizes are different than the existing size.

Table IV-4: Standard Distribution Main Replacement Sizes

<table>
<tr><th>Vintage Size</th><th>New Size</th><th colspan="3">Reasoning</th></tr>
<tr><td>¾” or 1 ¼”</td><td>2”</td><td colspan="3">2” is minimum main size the Company installs</td></tr>
<tr><td>2" PL/PE</td><td>2" PE</td><td colspan="3">No Change</td></tr>
<tr><td>2 ½”</td><td>2”</td><td colspan="3">2 ½” is not a common main size used by the industry, including Public Service</td></tr>
<tr><td>3”</td><td>4”</td><td colspan="3">3” is not a common main size used by the industry, including Public Service</td></tr>
<tr><td>4” PL/PE</td><td>4” PE</td><td colspan="3">No Change</td></tr>
<tr><td rowspan="3">4” Steel</td><td rowspan="3">6” PE</td><td colspan="3">Loss of Inside Diameter (“ID”) with 4” Steel to 4” PE</td></tr>
<tr><td><u>4" STL</u></td><td><u>4" PE</u></td><td><u>6" PE</u></td></tr>
<tr><td>4.188</td><td>3.71</td><td>5.347</td></tr>
</table>

<table>
<tr><th>Vintage Size</th><th>New Size</th><th colspan="3">Reasoning</th></tr>
<tr><td>6” PL/PE</td><td>6” PE</td><td colspan="3">No Change</td></tr>
<tr><td rowspan="3">6” Steel</td><td rowspan="3">8” PE</td><td colspan="3">Loss of ID with 6” STL to 6” PE</td></tr>
<tr><td><u>6" STL</u></td><td><u>6" PE</u></td><td><u>8" PE</u></td></tr>
<tr><td>6.249</td><td>5.347</td><td>7.125</td></tr>
<tr><td>8" PL/PE</td><td>8" PE</td><td colspan="3">No Change</td></tr>
<tr><td>10”</td><td>12”</td><td colspan="3">10” is not a common main size used by the industry, including Public Service</td></tr>
<tr><td>12"</td><td>12"</td><td colspan="3">No Change</td></tr>
</table>

Outside of standard diameter changes explained in Table IV-4, some pipeline diameter may be increased in order to resolve current operational constraints or meet future known load growth. One project added to AMRP scope in 2020, Country Hills Drive, increased the diameter of the existing main in order to increase the operating capacity of the area. Due to continued growth in Brighton, more capacity was needed for new housing developments. Increasing the main diameter upon replacement of the PVC main was the most cost-effective approach to providing the increased capacity. As a result, eighty percent of this project will be recovered under the PSIA rider and the remaining twenty percent will be recovered through Base Rates. Importantly, this project was not placed in service in 2020 and thus this will be addressed as part of the actuals report for 2021 projects. A one-pager for this project is included in Attachment 1.

<u>Change in Right of Way (“ROW”):</u>
AMRP encompasses many main replacements in established metropolitan areas of Colorado. As such, they are generally like-for-like replacements and are normally installed adjacent to existing lines with minimal ROW impact, when possible. In 2020, no AMRP projects involved a change in ROW.

<u>One Line Diagram:</u>
AMRP is composed of many defined projects and a list of those projects is supplied with this filing in the Scheduled Work List in Attachment 1. In addition, an electronic map file is available for viewing upon request.

DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM

Program Overview:

The Company's DIMP activities are focused on obtaining and evaluating information related to the distribution system that is critical for a risk-based, proactive integrity management program that involves programmatically remediating risks. The federal DIMP rules were promulgated by the PHMSA in 2009. The DIMP rules address how gas utilities identify, prioritize, and evaluate risks, identify and implement measures to address risks, and validate the integrity of their gas distribution system. Under the federal rule, pipeline operators were required to develop their DIMP plans on or before August 2, 2011. The Company published its DIMP plan in August 2011 and submitted it to the Commission on September 28, 2011.

Although the foundational requirements underlying the DIMP rule are similar to the TIMP rule: know your system (assets), identify the threats and risks to those assets, and proactively mitigate those threats. The requirements under the DIMP rule are less prescriptive than those under the TIMP rule. PHMSA determined that more general requirements were needed for distribution systems given the diversity of distribution systems and the unique threats to which they may be exposed.

The eight fundamental threats to the Company's distribution system are as follows:

- corrosion;
- natural forces;
- excavation damage;
- other outside force;
- materials, weld, or joint failure;
- equipment failure;
- incorrect operation; and
- other threats.

Program Description:

The Company's DIMP includes a variety of projects focused on advancing the primary elements of the program: know your assets, understand the risks and threats to your assets, and proactively mitigate risks. DIMP projects include:

- PPRP, exclusive of the AMRP;
- Distribution Valve Replacements; and
- Shorted Casing.

Key Activities and Costs since November 2019 PSIA filing:

The revenue requirement in the November 2019 PSIA filing was based on $53.1 million in planned DIMP capital expenditures. During the course of 2020, the Company continued focus on the replacement of higher risk mains and services under the PPRP program. Improved planning and financial forecasting along with better utilization of resources resulted in a net decrease of DIMP capital expenditures in 2020. Table IV-5 compares the

2020 actual and estimated DIMP capital expenditures, plant-in-service, and revenue requirement.

Table IV-5: 2020 DIMP Costs (All $ Values in Millions)

	Capital Expenditures	13 Month Average Plant In-Service	Revenue Requirement
2020 Estimate As Filed	$53.1*	$376.90	$36.32
2020 Actual	$51.0*	$358.31	$33.65
Variance	($2.1)	($18.59)	($2.67)
Percentage Variance	(4.0%)	(4.93%)	(7.35%)

Note: Variance calculations were performed at $000's.
* Base amount related to Leadville included in totals above, but not recovered through the PSIA Rider.

Overall DIMP expenditures were four percent lower than estimated. The primary variance driver was risk mitigation efficiency resulting in projects completed below estimate.

Additional DIMP variance assessments at the subprogram level are provided in the following sections.

Programmatic Risk-Based Pipe Replacement Program

Project Summary:
This replacement program includes three pipe types: Vintage Steel mains, Coupled Intermediate Pressure ("IP") mains, and Aldyl-A mains and services. The pipe segments targeted for replacement are risk-ranked based on history of leakage, including pipes with issues associated with corrosion prevention coating or cathodic protection as identified through direct assessment, as well as materials addressed in PHMSA advisory bulletins such as Aldyl-A and those pipes utilizing compression couplings.

Project Scope:
The program targets Vintage Steel mains, Coupled IP mains, and Aldyl-A mains and services.

Overall Program Status:
Through December 31, 2019, 185 miles out of a targeted 334 miles had been completed. In 2020, 31.6 additional miles of distribution/IP main were replaced, bringing the program to 65 percent complete based on the targeted 334 miles, reflected in the current PSIA. In addition, over 1,300 services were renewed during 2020.

Key Activities and Costs since November 2019 PSIA filing:
The revenue requirement in the November 2019 PSIA filing was based on the Company's plan to replace 16.6 miles of pipe under PPRP in 2020. Table IV-6 and Table IV-7 provide the variances between estimated and actual 2020 PPRP activities and capital expenditures.

Table IV-6: 2020 PPRP Construction Activities

Main Type Replaced	2020 Estimate As Filed (miles)	2020 Actual (miles)	Variance
Vintage Steel	14.6	22.1	7.5
Aldyl-A	1.5	4.2	2.7
Coupled IP	0.6	5.2	4.6
Total	**16.6**	**31.6**	**14.8**

Service Type Replaced	2020 Estimate As Filed (# of Services)	2020 Actual (# of Services)	Variance
Vintage Steel	1,805	1,161	(644)
Aldyl-A	*	151	151
Coupled IP	-	2	2
Total	**1,805**	**1,314**	**(491)**

***Quantities are based on the rate at which the materials that needed remediation are identified.

Table IV-7: 2020 PPRP Costs (All $ Values in Millions)

	Capital Expenditures
Vintage Steel	
2020 Estimate As Filed	$27.0
2020 Actual	$30.1
Variance	$3.1
Percentage Variance	11.4%
Aldyl-A	
2020 Estimate As Filed	$2.4
2020 Actual	$2.5
Variance	$0.1
Percentage Variance	5.5%
Coupled IP	
2020 Estimate As Filed	$13.7
2020 Actual	$9.8
Variance	($4.0)
Percentage Variance	(28.6%)

Note: Percentage variance due to rounding. See Attachment 3 for Capital Expenditures.

The following provides 2020 activity variance assessments for each material type.

Vintage Steel

During 2020, the Vintage Steel project focused on replacing specific sections of vintage coated steel pipelines in the distribution system identified as being in poor condition through the Company's risk model and subject matter expert review.

Overall, capital expenditures were approximately $3.1M higher than estimated and the main miles replaced were greater than estimated. The primary driver for increased expenditures was improved planning and financial forecasting to allow for additional work to be added to the 2020 scope. The lower cost per mile can be attributed to better project management and risk mitigation which reduced labor costs and eliminated many unanticipated expenses. See Project Summary, Attachment 1, for additional details on capital expenditure variance and current status.

Problematic Polyethylene/Aldyl-A Mains & Services

Overall, capital expenditures for Aldyl-A were greater than estimated. The primary driver for increased expenditures was the increased mileage of Aldyl-A main replaced due to an increase in the 2020 scope of work. In the end, the lower cost per foot for the Aldyl-A replacement can be attributed to an improved utilization of resources and extending projects where crews were already mobilized. See Project Summary, Attachment 1, for additional details on capital expenditure variance and current status.

Coupled IP Pipe Replacement

Overall, capital expenditures were $4.0M lower than the November 2019 filing estimate. The primary driver for the variance was completion of the Blake Street 2020 Phase ahead of schedule and under budget due to sound project management and identifying and mitigating risks before commencing work. See Project Summary, Attachment 1, for additional details on capital expenditure variance and current status.

Code Reference:

- 49 C.F.R. § 192.1007(d)
- The Aldyl-A replacement program was generated due to the Advisory Bulletins on the brittle cracking tendencies of that resin.
- ADB-07-01: http://www.gpo.gov/fdsys/pkg/FR-2007-09-06/pdf/07-4309.pdf
- ADB-02-07: http://www.gpo.gov/fdsys/pkg/FR-2002-12-03/pdf/02-30615.pdf
  PHMSA has released advisory bulletins concerning potential risks of mechanical compression couplings.

Changes in Pipeline Capacity:

PPRP encompasses many main replacements in established metropolitan areas of Colorado. Generally, projects are like-for-like replacements with little to no impact on capacity. The standard replacement size based on the existing size is shown in

Table IV-8 below includes a description of why some sizes are different than the existing size.

Table IV-8: Standard Distribution Main Replacement Sizes

<table>
<tr><th>Vintage Size</th><th>New Size</th><th colspan="3">Comments</th></tr>
<tr><td>¾” or 1 ¼”</td><td>2”</td><td colspan="3">2” is minimum main size the Company installs</td></tr>
<tr><td>2" PL/PE</td><td>2" PE</td><td colspan="3">No Change</td></tr>
<tr><td>2 ½”</td><td>2”</td><td colspan="3">2 ½” is not a common main size used by the industry, including Public Service</td></tr>
<tr><td>3”</td><td>4”</td><td colspan="3">3” is not a common main size used by the industry, including Public Service</td></tr>
<tr><td>4” PL/PE</td><td>4” PE</td><td colspan="3">No Change</td></tr>
<tr><td rowspan="3">4” Steel</td><td rowspan="3">6” PE</td><td colspan="3">Loss of Inside Diameter (“ID”) with 4” Steel to 4” PE</td></tr>
<tr><td><u>4" STL</u></td><td><u>4" PE</u></td><td><u>6" PE</u></td></tr>
<tr><td>4.188</td><td>3.71</td><td>5.347</td></tr>
<tr><td>6” PL/PE</td><td>6” PE</td><td colspan="3">No Change</td></tr>
<tr><th>Vintage Size</th><th>New Size</th><th colspan="3">Comments</th></tr>
<tr><td rowspan="3">6” Steel</td><td rowspan="3">8” PE</td><td colspan="3">Loss of ID with 6” STL to 6” PE</td></tr>
<tr><td><u>6" STL</u></td><td><u>6" PE</u></td><td><u>8" PE</u></td></tr>
<tr><td>6.249</td><td>5.347</td><td>7.125</td></tr>
<tr><td>8" PL/PE</td><td>8" PE</td><td colspan="3">No Change</td></tr>
<tr><td>10”</td><td>12”</td><td colspan="3">10” is not a common main size used by the industry, including Public Service</td></tr>
<tr><td>12"</td><td>12"</td><td colspan="3">No Change</td></tr>
</table>

In some cases, the pipeline diameter may be increased to resolve current operational constraints or meet future known load growth (as shown in the Project Summary, Attachment 1). Furthermore, consistent with the November filing for 2020 projects, and as reflected in Attachment 1, the 7800-8008 Grandview Ave replacement project (PPRP – Vintage Steel) included a diameter increase for a portion of the project. The total to replace the 1 1/4" mill wrapped main and 4" mill wrapped main with 4" PE and associated services was $102,676 under CSMR. The current configuration is 4-inch pipe transitioning to 1 1/4-inch pipe and then back to 4-inch pipe. The Company replaced the entire length with 4-inch pipe at a cost savings of approximately $5,000 due to elimination of the transitions. On the Leadville project (PPRP-Vintage Steel), the incremental portion attributed to increasing the diameter size of the pipeline (main renewal) is excluded from recovery through the PSIA.

Change in ROW:

PPRP encompasses many main replacements in established metropolitan areas of Colorado. As such, they are generally like-for-like replacements and are normally installed adjacent to existing lines with minimal ROW impact, when possible. In 2020, no PPRP projects involved a change in ROW.

One Line Diagram:

PPRP is composed of many defined projects and a list of those projects is supplied with this filing in the Scheduled Work List in the Project Summary, Attachment 1. In addition, an electronic map file is available for viewing upon request.

Distribution Valve Replacement Project

Project Summary:

The Distribution Valve Replacement Project is to replace key distribution valves which allow the Company to isolate areas in the system if needed to respond to an emergency situation, efficiently perform maintenance, and/or decrease the impact on customers. The Company's prioritization of valve replacements was based on an evaluation of the operating characteristics of existing valves.

Overall Project Status:

This project was initiated in 2013 to replace existing distribution system isolation valves (maximum operation pressure $\leq$285 psig), providing isolation capabilities. Overall, 98 valves across 53 locations have been completed.

Project Scope:

The project is targeting replacement of key distribution valves.

Key Activities and Costs since November 2019 PSIA filing:

The revenue requirements in the November 2019 PSIA filing were based on the Company's plan to replace an additional 13 valves across four locations. The Company replaced 16 valves across 5 locations, in 2020. Table IV-9 and Table IV-10 below provide the variances between estimated and actual activities during 2020.

Table IV-9: 2020 Distribution Valve Construction Activities

	2020 Estimate As Filed (each)	2020 Actual (each)	Variance
Locations	4	5	1
Valves	13	16	3

Table IV-10: 2020 Distribution Valve Costs
(All $ Values in Millions)

	Capital Expenditures
2020 Estimate As Filed	$6.0
2020 Actual	$6.0
Variance	($0.0)
% Variance	(0.7%)

Note: Variance calculations were performed at $000's.

In 2020, the four projects listed in the filing were completed as planned. Three additional valve projects were added to 2020 work scope and one was completed in 2020. The additional project that was completed was at University Blvd and County Line Rd and was in response to an emergency valve leak. This project highlights the importance of the Distribution Valve Replacement Project (and the entire DIMP Program) and how flexibility among DIMP projects enables the mitigation of risks as they arise. In the end, more locations were addressed, and more valves were replaced than originally estimated. Additionally, engineering work began on 2021 projects to help ensure timely completion of future projects.

See Project Summary, Attachment 1, for additional detail on capital expenditures and status.

<u>Code Reference:</u>
49 C.F.R. § 192.1015(b)(4)

<u>Changes in Pipeline Capacity:</u>
No change to pipeline capacity.

<u>Change in ROW:</u>
The majority of the valves identified for replacement are located within road ROW of heavily travelled intersections. As a result, the replacements are installed adjacent to the existing location to minimize disruptions. See Project Summary, Attachment 1 for additional detail.

<u>One Line Diagram:</u>
See Project Summary, Attachment 1, for the associated One Line Diagrams.

Shorted Casing

Project Summary:
Casings were routinely installed for a variety of situations including under roads and railroads. Pipelines were installed inside the casings to protect the pipe from a variety of forces. Improved design has mostly eliminated the use of casings in modern gas construction. The Company has a number of casings where it cannot determine if the pipeline carrying gas is isolated from the casing, a situation that can create a corrosion risk and lead to pipeline failure. The objective of this project is to mitigate the risk by renewing the pipeline or installing equipment that allows ongoing testing to ensure isolation. The ability to test for isolation is in accordance with the Company's Gas Standards Manual section 9.9.2, which states that, for all metallic carrier pipe installed in a metallic casing, the Company shall take pipe-to-soil and casing-to-soil readings annually with the purpose of determining whether the two pieces of pipe are in contact (shorted).

Project Scope:
The Company assumes all casings that cannot be tested for isolation between the carrier pipe and the casing are shorted (electrically continuous) until test leads can be installed and tested. If testing shows the pipe and casing are isolated, the casing is added to an annual test list and will be monitored and maintained over time. If testing shows no isolation (shorted), the casing will be renewed under this project. Some casings were installed when road ROW was narrower and casings were not extended when the road was widened. In these cases, the Company renews the carrier pipe and eliminates the casing, thus removing the corrosion risk.

Overall Project Status:
This project was initiated in the second half of 2014. In 2017, the focus shifted from survey to replacement. At the end of 2020, forty-one replacements had been completed.

Key Activities and Costs since November 2019 PSIA filing:
The Company planned to replace four shorted casings in 2020 and ultimately replaced one. Table IV-11 shows the planned and actual work activities for 2020. Table IV-12 provides a comparison of 2020 actual and estimated capital expenditures.

Table IV-11: 2020 Shorted Casing Activities

	2020 Estimate As Filed	2020 Actual	Variance
Casings	4	1	(3)

Table IV-12: 2020 Shorted Casing Costs (All $ Values in Millions)

	Capital Expenditures
2020 Estimate As Filed	$4.0
2020 Actual	$2.6
Variance	($1.4)
% Variance	(34.1%)

Note: Variance calculations were performed at $000's.

The primary drivers for decreased project completion and capital expenditures in 2020 were permitting challenges and one project being removed from the 2020 work scope. The unforeseen significant permitting challenges resulted in the W. 64th project being delayed and only partially complete in 2020. The casing on the Pierce St project was discovered to be a non-metallic material and not shorted. As a result, it was removed from the program scope of work. Additional information is provided in the Project Summary, Attachment 1.

Changes in Pipeline Capacity:
No change to pipeline capacity.

Change in ROW:
No change in ROW.

One Line Diagram:
See the Project Summary, Attachment 1, for the associated One Line Diagram.

B. Transmission Programs

Program Overview:
The Company's TIMP complies with federal TIMP regulations that prescribe how operators validate the integrity of gas transmission assets, with the highest priority given to those located in HCAs.

Program Description:
TIMP initiatives generally fall within the following four project categories:

- Transmission Pipeline Health and Condition Assessments and Repairs;
- Maximum Allowable Operating Pressure ("MAOP") verification, including data and record verification as well as validating and documenting the safe, allowable pressure for pipeline segments;
- Automatic Shut-off/Remote Control ("ASV/RCV") for gas transmission valves; and

- Shorted Casings – Transmission.

Key Activities and Costs since November 2019 PSIA filing:

The forecasted revenue requirement in the November 2019 PSIA filing was based on $74.0 million in planned TIMP capital expenditures. Table IV-13 compares 2020 actual and estimated capital expenditures, 13-Month Average Plant-In-Service, and Revenue Requirement for TIMP.

Table IV-13: 2020 TIMP Actual to Estimated Costs
(All $ Values in Millions)

	Capital Expenditures	13 Month Average Plant In-Service	Revenue Requirement
2020 Estimate As Filed	$74.0	$421.90	$35.71
2020 Actual	$63.6	$407.80	$33.78
Variance	($10.4)	($14.10)	($1.93)
% Variance	(14.0%)	(3.34%)	(5.40%)

Note: Variance calculations were performed at $000's.

The TIMP under-run is largely driven by lower than planned project costs and delays in construction activities within the MAOP and ASV / RCV program expenditures. The primary drivers for MAOP were permitting delays on SE Metro and project scope changes on the 10" Mesa to Boulder project that led to delays in construction and project completion. Engineering and construction on several projects were pulled forward to 2020 where feasible. ASV/RCV program expenditures incurred a variance due to the deferral of two large projects from 2020 to 2021 construction scope, as well as, more favorable construction pricing.

Additional TIMP variance assessments at the subprogram level are provided in the following sections.

Transmission Pipeline Assessments and Repairs Project

Project Summary:

This project performs health and condition assessments of transmission pipelines under 49 C.F.R. Part 192 Subpart O, "Gas Transmission Pipeline Integrity Management." The federal code requires assessment of transmission pipelines using limited approved methods including In Line Inspection ("ILI"), Pressure Testing, or Direct Assessment. The requirements are further defined in the Company's TIMP manual. The federal regulation requires operators to ensure the safe operation of pipelines on a repetitive interval of no more than seven years.

The Company has selected ILI as its primary assessment methodology, as this methodology yields the most comprehensive information to address transmission system threats. However, depending on the identified threat, alternative and/or additional assessment methodologies may also be utilized. These additional methods include, but may not be limited to, External Corrosion Direct Assessment ("ECDA") and pressure tests. The TIMP rules require the Company to apply knowledge gained from assessments to all similar pipelines within the system.

Once all applicable threats are evaluated, a pipeline is classified as having a baseline assessment, with subsequent reassessments required at regular intervals not to exceed seven years. While the initial investment incurred to make the lines accessible to ILI tools can be significant, this investment provides long-term benefits by allowing the Company to monitor changes to the health and condition of a line well into the future. In addition, ILI tool technology continues to evolve at a rapid pace, and the Company expects further benefits based on this changing technology.

The Company evaluates anomalous conditions found during the assessment, including the location, severity, nature (threat cause), and type of feature (e.g., dent or metal loss). The Company then categorizes the anomaly into an immediate condition, a one–year condition, or a monitored condition, which establishes the priority of remediation. Typical remediation measures include excavation and repair or complete removal of the anomaly, pipe replacement, and/or reducing the operating pressure of that section of the system.

Overall Project Status:

This project began in 2002 with the federal requirement to perform a baseline assessment on pipelines within HCAs by December 17, 2012. The Company met those requirements and is now focused on re-assessing mains in HCAs -- as dictated by the baseline assessments -- as well as assessing the transmission system beyond HCAs.

Key Activities and Costs since November 2019 PSIA filing:

Table IV-14 shows the 2020 Transmission Pipeline Assessments work plan, which included preparing pipelines for ILI also referred to as "make piggable," performing integrity assessment utilizing ILI, and pipeline de-rate projects. In addition, the actual 2020 work plan included repairs to existing pipelines because of inspection findings. Inclusion of such repairs as PSIA expenditures was based on repair type and the Company's capitalization policy. Table IV-15 provides a comparison of 2020 actual and estimated capital expenditures including capitalized repair work.

Table IV-14: 2020 Transmission Pipeline Assessments and Repairs Activities

	2020 Estimate As Filed	2020 Actual	Variance
ILI Runs	80.4 miles	24.7 miles	(55.7) miles

Table IV-15: 2020 Transmission Pipeline Assessments and Repairs Costs (All $ Values in Millions)

	Capital Expenditures
2020 Estimate As Filed	$8.1
2020 Actual	$9.4
Variance	$1.3
% Variance	16.0%

Note: Variance calculations were performed at $000's.

The primary driver for Transmission Pipeline Assessment and Repair variances were the additional work scope and complexities of several projects, including, but not limited to:

- Current Year Additions:
  - 20"(24") SPMS-Blakeland to S Wadsworth: Horizontal direction drill (HDD) replacement for railroad anomaly.
  - 12" Golden (make piggable): Launcher and receiver valve set modifications needed to launch and receive ILI tools.
- 6" Gary Western Lateral (6" Fruita Turbine Gen) (make piggable): Additional valve set modifications.
- Anomaly Repairs from Prior ILI: 6"(8") Climax to Vail Village C-SCC Repairs, 8" Ignacio-Del Norte, and 6" Upper Arkansas pipeline anomaly repairs resulting from 2018, 2019, and 2020 ILI runs.

Additional information is provided in Project Summary, Attachment 1.

<u>Code Reference:</u>
49 C.F.R. § 192 Subpart O

<u>Changes in Pipeline Capacity:</u>
See the Project Summary, Attachment 1, for additional detail.

<u>Change in ROW:</u>
See the Project Summary, Attachment 1, for additional detail.

<u>One Line Diagram:</u>
See the Project Summary, Attachment 1, for additional detail.

Maximum Allowable Operating Pressure Project

<u>Project Summary:</u>
Construction practices, pipeline material and manufacturing methods have changed over the course of decades as the Company's transmission pipelines were installed. The codes and rules around material testing, welding standards, and pipeline record keeping have also become more stringent. Consequently, the Company's legacy assets have varying degrees of record gaps. Some record gaps are more critical than others. For instance, records supporting the construction and maintenance of gas transmission pipelines and operating pressures are ones that are deemed critical to the safe operation of these assets.

PHMSA's Safety of Gas Transmission Pipelines Final Rule (Docket No. PHMSA–2011–0023) requires operators to take action as appropriate to assure that all MAOP and Maximum Operating Pressure ("MOP") are supported by records that are traceable, verifiable and complete.

This project focuses on prioritized remediation of record gaps based on a variety of factors including: location of the pipeline, type(s) of missing documentation, criticality to system, whether health and condition assessments have occurred on the pipeline, and vintage. Remediation options include replacement, de-rate, or pressure test and material validation.

<u>Overall Project Status:</u>
In 2020, the Company continued to focus on validation of MAOP and identifying record gaps. This effort is necessary to identify record gaps warranting remediation which is primarily an operations and maintenance ("O&M") expense and is not covered within the PSIA. The portion of this project covered within the PSIA continues to focus on the prioritized remediation and associated options of pipelines with record gaps.

<u>Key Activities and Costs since November 2019 PSIA filing:</u>
The Company's November 2019 filing included $37.4 million in capital expenditures for remediation projects. Table IV-16 and Table IV-17 provide the 2020 actual and estimated capital expenditures and status related to MAOP remediation projects.

Table IV-16: 2020 MAOP 2020 Activity Summary
(All $ Values in Millions)

Line Name	2020 PSIA Estimate As Filed	2020 Actual	Status
1. Southeast Metro Project (20" Parker)	$25.0M	$16.2M	USACE permitting process delayed ability to complete the pipeline segments within Cherry Creek State Park that were originally anticipated to be completed in 2020.
2. 10" Mesa-Boulder – Westlake to Boulder Junction	$6.2M	$0.1M	Project extended from original filing to include additional areas that were identified to be in a class 3 location and missing pressure test documentation. Construction start deferred to late 2021. Engineering and permitting started in 2020.
3. 6" Estes Park	$4.8M	$0.0M	Engineering to begin on project in 2020. Project scope was extended to include all class 3 locations missing records information along pipeline, thus construction deferred to 2021.
4. 3" East Hayden	$0.3M	$0.0M	Additional records were found and it was determined that remediation was no longer required.
5. 10" Mesa to Boulder - Gaylord	$0.0M	$6.2M	Pipeline is missing pressure test documentation in a class 4 location. Construction accelerated to 2020.
6. 8" Battle Mountain to Minturn	$0.0M	$0.0M	Engineering and permitting to start in 2020, construction anticipated to begin in 2021.
7. 10" Mesa to Boulder – I-76 to Skylake	$0.0M	$0.5M	Engineering and permitting started in 2020. Some minor construction completed in 2020, with major construction anticipated to begin in 2021.
8. 6" Fort Lupton Electric Trans	$0.0M	$1.9M	Project identified to be missing pressure test documentation in a class 3 location. Construction started in 2020; however, project could not be in serviced in 2020.
9. 3" (4") East Hayden to Steamboat	$0.0M	$4.1M	Project accelerated to 2020 plan. Pipeline did not have pressure test record information within a class 3 location. Brushfires in the area caused remaining construction to be pushed to 2021.
10. Pre-Engineering for 2021 Projects	$1.1M	$0.0M	See project details in Attachment 7 for projects that began engineering for 2021 projects.
11. 2019 Carryover	$0.0M	$0.1M	
Total	**$37.4M**	**$29.3M**	

*Excludes costs associated with the increased pipe diameter not recovered through PSIA.

Table IV-17: 2020 MAOP Actual to Estimated Costs (All $ Values in Millions)

	Capital Expenditures
2020 Estimate As Filed	$37.4
2020 Actual	$29.3
Variance	($8.1)
% Variance	(21.7%)

Note: Variance calculations were performed at $000's.

Additional project level detail is provided in Project Summary, Attachment 1.

Code Reference:

- 49 C.F.R. § 192.619
- PHMSA's Safety of Gas Transmission Pipelines Final Docket No. PHMSA–2011–0023IVP PHMSA-2013-0119-0047

Changes in Pipeline Capacity:
See Project Summaries, Attachment 1, for additional detail.

Change in ROW:
See Project Summaries, Attachment 1, for additional detail.

One Line Diagram:
See Project Summaries, Attachment 1, for additional detail.

Automatic Shut-Off Valve/Remote Control Valve (ASV/RCV) Project

Project Summary:
The ASV/RCV Project objective is to install or modify existing valves with actuation and controls for remote or automatic operation, allowing faster shut down in the event of an unplanned gas release from gas transmission pipelines. The Company has been installing this type of equipment on various transmission pipelines to address existing TIMP requirements, which require the installation of an ASV/RCV at locations where the valves provide an efficient means of adding protection in the event of an unplanned gas release.

Rule 49 C.F.R. § 192.935(c) requires each Company to perform a risk analysis considering the following criteria to determine if adding an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release:

- swiftness of leak detection and pipe shutdown capabilities;
- type of gas being transported;
- operating pressure;
- rate of potential release;
- pipeline profile;
- potential for ignition; and

- location of nearest response personnel.

Subject matter experts worked with the Company's Quantitative Risk Services Department to identify and rank the identified sites. Further site-specific information was considered, including whether a pipeline was scheduled for replacement soon.

Section 4 of the 2011 Pipeline Safety Act (49 U.S.C. § 60102(n)) calls for the Secretary of the Department of Transportation ("DOT") to require by regulation the use of automatic or remotely controlled shutoff valves, or equivalent technology, where it is economically, technically, and operationally feasible. On August 25, 2011, PHMSA issued an advanced Notice of Proposed Rulemaking ("ANPRM") addressing ASV/RCVs and seeking comments on several broad areas for potentially expanding the TIMP rules. The NPRM for ASV/RCVs was recently published on February 6, 2020, and comments were requested by April 6, 2020. It proposes to mandate installation of automatic control valves or remote-controlled valves on new and replaced transmission lines of 6" or greater diameter. The NPRM also proposes emergency response criteria for detecting ruptures, verifying ruptures, response times, conducting emergency drills, and post-incident investigations.

Overall Project Status:

Based on current federal code requirements, 365 valves at 162 locations have currently been identified for installation of actuation and controls. Through December 31, 2020, 268 valve projects had been completed. In 2020, an additional 51 valve projects were completed, bringing the project to 73 percent complete based on targeted valves, reflected in the current PSIA.

Key Activities and Costs since November 2019 PSIA filing:

Table IV-18 shows the planned and actual activities for 2020. Table IV-19 provides a comparison of 2020 actual and estimated capital expenditures.

Table IV-18: 2020 ASV/RCV Construction Activities

	2020 Estimate As Filed (each)	2020 Actual (each)	Variance
Locations	14	19	5
Valves	32	51	19

Table IV-19: 2020 ASV/RCV Costs (All $ Values in Millions)

	Capital Expenditures
2020 Estimate As Filed	$14.2
2020 Actual	$11.1
Variance	($3.1)
% Variance	(22.1%)

Note: Variance calculations were performed at $000's.

The capital expenditures associated with the ASV/RCV Project include actuator installations, valve installations, valve replacements, Remote Terminal Units ("RTU") and associated electronics that are necessary for automatic shut-off capabilities. The 2020 variance is due to the deferral of two projects from 2020 to 2021 construction scope. The changes were incurred by permit delays and for more favorable construction pricing. Project Summary, Attachment 1 provides additional location level detail.

Code Reference:

- 49 C.F.R. § 192.935(c)
- Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, Section 4, codified at 49 U.S.C. § 60102(n)

Changes in Pipeline Capacity:
See Project Summary, Attachment 1, for additional detail.

Change in ROW:
See Project Summary, Attachment 1, for additional detail.

One Line Diagram:
See Project Summary, Attachment 1, for additional detail.

Shorted Casing – Transmission

Project Summary:
This project is similar to the shorted casing – Distribution Project (see prior discussion). As an integrated part of the Company's DIMP plan, and in response to the request made by the Commission on November 13, 2013, the Company instituted a gas standard (9.9.2), which states, in part, the Company will perform "for all metallic pipe installed in a metallic casing, pipe-to-soil and casing-to-soil readings annually with the purpose of determining whether the two of them are in contact (shorted) or not." Similar needs have now been identified as part of TIMP for Transmission pipelines which is a principle requirement of managing risk under integrity management programs.

Metallic pipes need to remain isolated from each other to reduce corrosion risk. The Company's Gas Standards Manual section 9.9.2 and 49 C.F.R. § 192.467 provide that for all metallic carrier pipe installed in a metallic casing, the Company shall take pipe-to-soil and casing-to-soil readings annually to determine whether the two pieces of pipe are in contact with each other, and thereby considered to be shorted. If the Company is unable to verify those readings and/or the readings indicate that both the pipe and casing are in contact, the Company shall perform gas leak surveys a minimum of two times per year – four times per year in business districts – given the potential for corrosion between the two pieces of pipe.

Under this project, the Company isolates pipes and casings that are determined to be shorted (in contact), mitigates leakage risk for sites that indicate the presence of corrosion or where testing has not occurred, and replaces pipe where it is not possible to test or isolate the pipe.

Overall Project Status:
The project was initiated in 2017 as a result of 2015 survey activities. Since inception, sixteen casings have been remediated.

Key Activities and Costs since November 2019 PSIA filing:
The Company planned to replace nine shorted casings in 2020. Due to the coronavirus pandemic, the engineering/ROW efforts on these projects were delayed due to limited abilities of permitting agencies. The 20" EDC and the 26" EDC projects were not executed in 2020. The program faced increased costs with some projects growing in complexity from the design process. Table IV-20 shows the planned and actual work activities for 2020. Table IV-21 provides a comparison of 2020 actual and estimated capital expenditures.

Table IV-20: 2020 TIMP Shorted Casing Activities

	2020 Estimate As Filed	2020 Actual	Variance
Casings	9	7	(2)

Table IV-21: 2020 TIMP Shorted Casings Costs (All $ Values in Millions)

	Capital Expenditures
2020 Estimate As Filed	$14.3
2020 Actual	$13.9
Variance	($0.4)
% Variance	(3.0%)

Note: Variance calculations were performed at $000's.

Code Reference:
49 C.F.R. § 192.467

Changes in Pipeline Capacity:
See Project Summary, Attachment 1, for additional detail.

Change in ROW:
See Project Summary, Attachment 1, for additional detail.

One Line Diagram:
See Project Summary, Attachment 1, for additional detail.

Other April PSIA Actuals Report Requirements

This section addresses the annual PSIA report content requirements, as established pursuant to Commission decisions, including Decision No. R14-0694 in Proceeding No. 13M-0915G and Decision No. R14-0736 in Proceeding No. 10AL-963G that is not otherwise reported above or in the attached appendices for the PSIA Annual Report.

Changes to Project Costs Requiring Approval of Investment Review Council, Finance Council or Board of Directors (Decision No. R14-0736, Appx. 1, pp. 8-9, ¶ 23). There was no Investment Review Council, Financial Council, or Board of Directors project change requests for the year of 2020.

Changes to Contract Change Order Authorizations (Decision No. R14-0736, Appx. 1, pp. 8-9, ¶ 23). There were no changes made to the Company's contract change order authorization policy.

DOT Annual Leak Reports (Decision No. R14-0694, Appx. 1, p. 11, ¶ 5). The Company's leak records as reported in the 2020 annual DOT report is provided as Attachment 5.

Management's Request for Explanations, Analyses to Management and Plans to Remedy Cost Overruns (Decision No. R14-0694, Appx. 1, p. 10, ¶ 3). The Rider Review Committee ("RRC") was formed in 2014 to increase structure, transparency, and documentation around capital and O&M expenditures related to the PSIA. The PSIA RRC meeting agendas, change requests and corresponding approvals to fulfill the request for explanations, analyses to management, and plans to remedy cost overruns will be made available to parties for review upon request. The resulting capital expenditures explanations of actual to estimated costs for 2020 are included in Attachment 2.

Contracts Relating to PSIA Project Work (Decision No. R14-0694, Appx. 1, p. 12, ¶ 5). A list of contracts and corresponding change orders, including vendor names, will be made available to parties for review upon request.