Xcel Energy®

RULE 3206 REPORT

PROPOSED NEW CONSTRUCTION OR EXTENSION OF TRANSMISSION FACILITIES

2024 THROUGH 2026

PROCEEDING NO. 23M-0005E

APRIL 28, 2023

CONTENTS

A. Introduction 3

1. Regulatory Background and Report Structure 3
2. Transmission Project Management and Cost Estimates 4

B. New Planned Projects That May Require a CPCN 9

C. New planned Projects for which Public Service Requests the Commission Determine a CPCN is Not Required Pursuant to the Commission's Rules, Precedent, and/or Because the Project is in the Ordinary Course of Business 10

1. Metro Water Recovery Transmission Service 11

D. Transmission Facilities Associated With the Implementation of the Colorado Energy Plan Portfolio in the Company's 2016 Electric Resource Plan 14

1. Sun Mountain Solar Interconnection 16

E. Status of Projects Listed in Prior Reports 19

F. Projects Presented for Commission Informational Purposes 26

1. Long Range Distribution Planning Substation Projects 26
2. 2021 Electric Resource Plan and Clean Energy Plan 26

A. INTRODUCTION

1. REGULATORY BACKGROUND AND REPORT STRUCTURE

In July of 2006, the Colorado Public Utilities Commission ("Commission" or "CPUC") adopted Rule 3206 as a part of 4 Code of Colorado Regulations ("CCR") 723-3, the Commission's rules regulating Electric Utilities. Rule 3206 sets forth requirements for new construction and extension of transmission facilities, and Rule 3206(d) requires applicable utilities, including Public Service Company of Colorado ("Public Service" or the "Company"), to file annual reports on its planned transmission facilities. The purpose of the Rule 3206 report is to notify the Commission of pending or planned transmission system work and help the Commission determine if such projects (1) require a Certificate of Public Convenience and Necessity ("CPCN") under Rule 3102 and § 40-5-101, C.R.S., (2) do not require a CPCN, or (3) are in the ordinary course of business.

This report includes Public Service projects that are planned to be implemented within the next three years and conceptual projects that the Company is considering but does not necessarily have planned in-service dates at this time. "Planned Projects" are projects for which Public Service generally has a level of commitment such that proposed schedules for completion have been drafted, site control has been established, and/or the project has received budgetary approvals. These include projects that are necessary to meet reliability and load growth needs, planned interconnection for new generation driven by the Company's Open Access Transmission Tariff ("OATT"), or to meet enacted state or federal public policy requirements, etc. The Company also includes alternatives considered for each Planned Project, including consideration of energy storage systems, consistent with Rule 3206(d)(I)(D). "Conceptual Projects," on the other hand, may not have specific in-service dates identified, and their implementation likely depends on numerous factors, some of which include forecasted load growth and generation needs, economic considerations, public policy initiatives, and regional transmission development.

This report is divided into several sections. The first section is this introduction which provides background information, a brief explanation of what is included with this filing, and additional information on the Company's transmission project management and cost estimation processes.

Section B includes new construction or extension projects that may require a CPCN under Commission rules. Public Service is not presenting any planned new construction or extension projects in this report.

Section C includes new projects for which the Company is requesting the Commission determine that a CPCN is not required pursuant to the Commission's Rules, precedent, and/or because the project is in the ordinary course of business. The Company is presenting four projects in this category.

Section D of this filing presents for Commission approval the final transmission facilities associated with the implementation of the Colorado Energy Plan Portfolio ("CEPP") in the Company's 2016 Electric Resource Plan ("ERP"). While the Company had intended to present a package of transmission facilities associated with the replacement projects acquired through the 2019 Solar Request for Proposals (the "2019 ERP Amendment") to the Commission for a CPCN, as discussed more below, the failure of one of the replacement projects has significantly reduced the scope of the remaining transmission facilities that the Company has developed associated with the CEPP and, in the interest of administrative efficiency, the Company is seeking Commission approval of the final CEPP transmission facilities through this Report.

Section E of this filing provides an update on projects that have been listed in past Rule 3206 filings, or for which the Company has initiated the CPCN process since its last Rule 3206 filing. Many of the updates in this section are due to updated forecasts because of refined project scopes and cost estimates since the last report. Projects are refined as they mature and more current material, labor, and price estimates including market pressures driven by supply chain constraints, labor shortages, and commodity price increases.

Section F of this filing includes projects generally considered conceptual at the time of filing and which are being provided for informational purposes only. This 2023 filing includes "Long Range Distribution Planning Substation Projects," however, as noted in this section the Company intends to work with Trial Staff of the Commission ("Commission Staff") and the Utility Consumer Advocate ("UCA") to transition reporting on this topic to other, more appropriate forums in future years. The Company also provides a discussion of additional types of transmission projects it anticipates bringing forward as part of future filings with the Commission but are not yet sufficiently developed to request specific findings on, in this filing.

2. TRANSMISSION PROJECT MANAGEMENT AND COST ESTIMATES

Public Service manages transmission construction and extension projects through its Project Life Cycle ("PLC"). The Company's Transmission Project Management group is responsible for managing the PLC process to develop, monitor, and control project scope, estimates/budget, schedule, and risks. Through the PLC, the Transmission Project Management group is responsible for coordinating the Company's groups that contribute to the identification, planning, and execution of projects including transmission planning, siting and land rights, procurement, and construction. The PLC provides clear directions for each stage and the approvals at each gate for all phases of the development of transmission capital projects – after project origination through planning, budget creation, financial approval, real estate acquisition, design, construction, commissioning, and closeout.

The Company's PLC includes seven specific stages: (1) project origination, (2) budget estimate package, (3) project budget approval, (4) project development, (5) engineering, (6) construction, and (7) project closeout. In order to move forward to the next stage, each project must go through a "gate" approval in which the project is reviewed within the context of the PLC requirements and a further decision is made as to whether or not to authorize the next stage of a project.

Projects managed through the PLC are classified into one of three tiers in order to match the level of rigor that project teams apply to each project based on general size and complexity. Tier classifications are dependent on the project's cost, significance and public impact, complexity, and environmental impact. Tier classifications determine the level of scrutiny for each project and ensure that the resources expended to manage a project through the PLC are commensurate with each project's needs. Tier classifications for projects also dictate the required reviews and approvals as projects progress through the stages and receive gate approvals.

Stage-Gate 3 is the when the Company considers a project to be sufficiently defined and to have received sufficient internal approval to report the project's scope, schedule, and cost to the Commission, for a determination or approval, through annual Rule 3206 Reports and required CPCN applications. Once a project has received Stage-Gate 3 approval, material changes to the scope, cost, or schedule of the project require additional internal approval. The level of authority needed to approve changes to a project past Stage-Gate 3 is dependent on the impact that the change has on the project.

Within the PLC, the Company develops several cost estimates during the life of a transmission project. The level of accuracy of a cost estimate is determined by the progress towards project completion. To generate these estimates, the Company uses a well-regarded software tool for developing cost estimates called InEight Estimate. Company engineers use InEight Estimate to develop detailed cost estimates by entering historical cost data and other relevant information into the program, which then calculates a cost estimate using those inputs. InEight Estimate provides a framework to organize extensive cost component reference data, assemble estimates, manage multiple versions of the cost estimate calculation, and generate summary and detail reports for a variety of project types. The user builds their own database of components and activities suitable to their projects and populates and maintains the unit prices and other factors. The Company uses this tool in developing cost estimates for its transmission line and substation projects.

The Company typically identifies four classifications of project estimates that may subsequently be generated for each transmission project: Indicative, Scoping, Appropriations, and Engineering Estimates. An Indicative Estimate carries no defined or implied level of accuracy and is based upon the initial understanding of the project and the estimator's experience, it is not developed for every project. It is typically an informal communication generally used for high-level alternative project comparisons and discussion. A Scoping Estimate is produced before engineering design and siting and land rights activities have begun or are only approximately 5 percent complete. Scoping-level estimates are typically used by the Company as part of the Applications for CPCNs filed with the Commission given the regulatory timing and processes around developing and processing a case at the Commission which occurs over many months. The next level of estimate, an Appropriations Estimate, refines a previously produced Scoping Estimate and improves the level of accuracy for budget and forecast purposes. It will be based on conditions expected to be encountered on the specific construction project and should include a site visit. The engineering and design work may be approximately 5-25 percent complete; the land acquisition work should generally be approximately 5-25 percent complete, while permitting and siting work should be approximately 60-80 percent complete. Finally, the most accurate level of estimate that the Company develops is an Engineering Estimate, which includes the best material and equipment information available. Permitting, siting, and land acquisition work should be approximately 80-100 percent complete. The engineering should be approximately 75-100 percent complete; material costs are usually known with certainty; materials with long lead time items are usually ordered. At the Engineering Estimate stage, construction costs are still unknown, and remaining risks may still be accounted for in the project's cost estimate.

Within the PLC, an Indicative Estimate is developed in Stage 1, a Scoping Estimate is developed at Stage 2, an Appropriation Estimate is developed at Stage 4, and an Engineering Estimate is developed at Stage 5.

Risk identification and management is a key component of prudent project management, and the Company's management of transmission projects accounts for ways in which the final spend on a project many months and often several years in advance of completion is ultimately unknown. While the Company has historically included a contingency as part of a transmission project cost estimate when applying for a CPCN, the Company no longer develops cost estimates that include set percentages above and below the stated cost estimate to account for the uncertainty associated with the development and construction of its transmission cost estimates. The Company's cost estimation process now more granularly accounts for uncertainties through the development of a risk reserve forecast. Each cost estimate includes a project-specific risk reserve for categories of costs where necessary expenditures may increase if a risk event occurs. The types of risk events that the Company may account for when developing the risk reserve forecast include, among other issues, construction delays (which may be related to, among other things, supply or transport issues, hindrances encountered on the land, access to roads, or local jurisdiction permitting issues), problems with material supplies (including delivery timing, quality issues, or unanticipated equipment failure), fluctuations in prices of equipment (which may related to international tariffs, commodity price changes, and industry demand), weather-related delays or issues, licensing and permitting issues unique to the location (such as railroad licenses or jurisdictionally-mandated mitigation requirements), or changes in project scope due to other circumstances. The risk reserve reflects an assigned cost component for those anticipated risks at the time of cost estimation. A specific risk reserve amount is based on the estimated cost to incur the risk event and the probability of the risk event occurring. The risk reserve amount is typically determined based on a qualitative and quantitative evaluation of the activities and plans for the project, using the Company's engineers' experience with similar projects or project components. The use of a risk reserve allows the Company to account for unknowns with some granularity for specific identified risks, based on the amount of engineering, siting and land rights activities, and other work the Company has completed at the time the cost estimate is developed.

Unless otherwise stated, all costs and budgets in this filing are "Transmission Costs," which Public Service considers to be the procured costs of each project's physical Transmission Facilities as defined by Rule 3001(kk) plus the associated subsidiary costs necessary to design, install, and operate those facilities. In keeping with Rule 3001(kk), "Transmission Facilities" are "those lines and related substations designed and operating at voltage levels above the utility's voltages for distribution facilities, including but not limited to related substation facilities such as transformers, capacitor banks, or breakers that are integral to the circuitry of the utility's transmission system." More specifically, for purposes of this Report, Transmission Costs include cost estimates associated with high voltage transmission devices and machines, labor and contractor rates, materials, overhead, contingency reserves, transmission land acquisition, transmission rights-of-way, and engineering.

Public Service does not include distribution-level voltage facilities (such as dedicated substations and feeders), generation facilities, which may (or may not) include bulk energy storage as part of their injection capabilities/technology, or distribution siting and land rights activities in its Transmission Costs. The Company does, however, typically provide relevant distribution and distribution land costs in applicable CPCN applications. Unless otherwise noted, all costs listed in this filing are Transmission Costs as defined above.

Due to the fact that Transmission Cost estimates are refined during a project's lifecycle, as described above, the Transmission Cost estimates presented in this report are subject to change.

B. NEW PLANNED PROJECTS THAT MAY REQUIRE A CPCN

Public Service is not presenting any planned new construction or extension projects that may require a CPCN in this report.

C. NEW PLANNED PROJECTS FOR WHICH PUBLIC SERVICE REQUESTS THE COMMISSION DETERMINE A CPCN IS NOT REQUIRED PURSUANT TO THE COMMISSION'S RULES, PRECEDENT, AND/OR BECAUSE THE PROJECT IS IN THE ORDINARY COURSE OF BUSINESS

1. Metro Water Recovery Transmission Service

1. METRO WATER RECOVERY TRANSMISSION SERVICE

Project Description and Purpose

Metro Water Recovery is an existing electric service customer in the Denver metropolitan area that has requested to convert from distribution to transmission service in-order to meet their increased load.

This project will include tapping and looping (approximately 0.2 miles) the existing 115kV overhead line 9548 in-and-out of a new switching station. The transmission taps will be rated at 159.3 MVA to match the rating of the existing circuit. The new switching station will be a 115kV four (4) breaker ring switching station constructed by Public Service to provide transmission service to this customer. The switching station will not include any transformers. The new switching station will be located on land currently owned by Metro Water Recovery that will be deeded to Public Service at no cost. This installation will also require remote end line terminal upgrades of Line 9548 at the existing Cherokee and Thornton Substations as well as extending optical ground wire from Cherokee to Line 9548.

Project Alternatives Considered

In addition to the project identified above, the Company also evaluated looping the 5309 Cherokee – Riverside 230 kV line into the new switching station. This alternative was rejected by the customer because the customer has requested 115 kV service instead of 230 kV service. Battery storage was not determined to be a viable alternative to the project as it cannot replace the transmission facilities needed to physically connect the customer's facilities to the Public Service transmission system.

Estimated Transmission Cost of the Project

$16 million, Scoping cost estimate. The customer will fund 100 percent of the project.

Date for the Start of Construction of the Project

March 2023

Estimated Date of Completion of the Project

January 2025

Estimated In-Service Date of the Project[1]

October 2024

Proposed General Location

Near the intersection of 64th Avenue and York Street in Unincorporated Adams County, Colorado

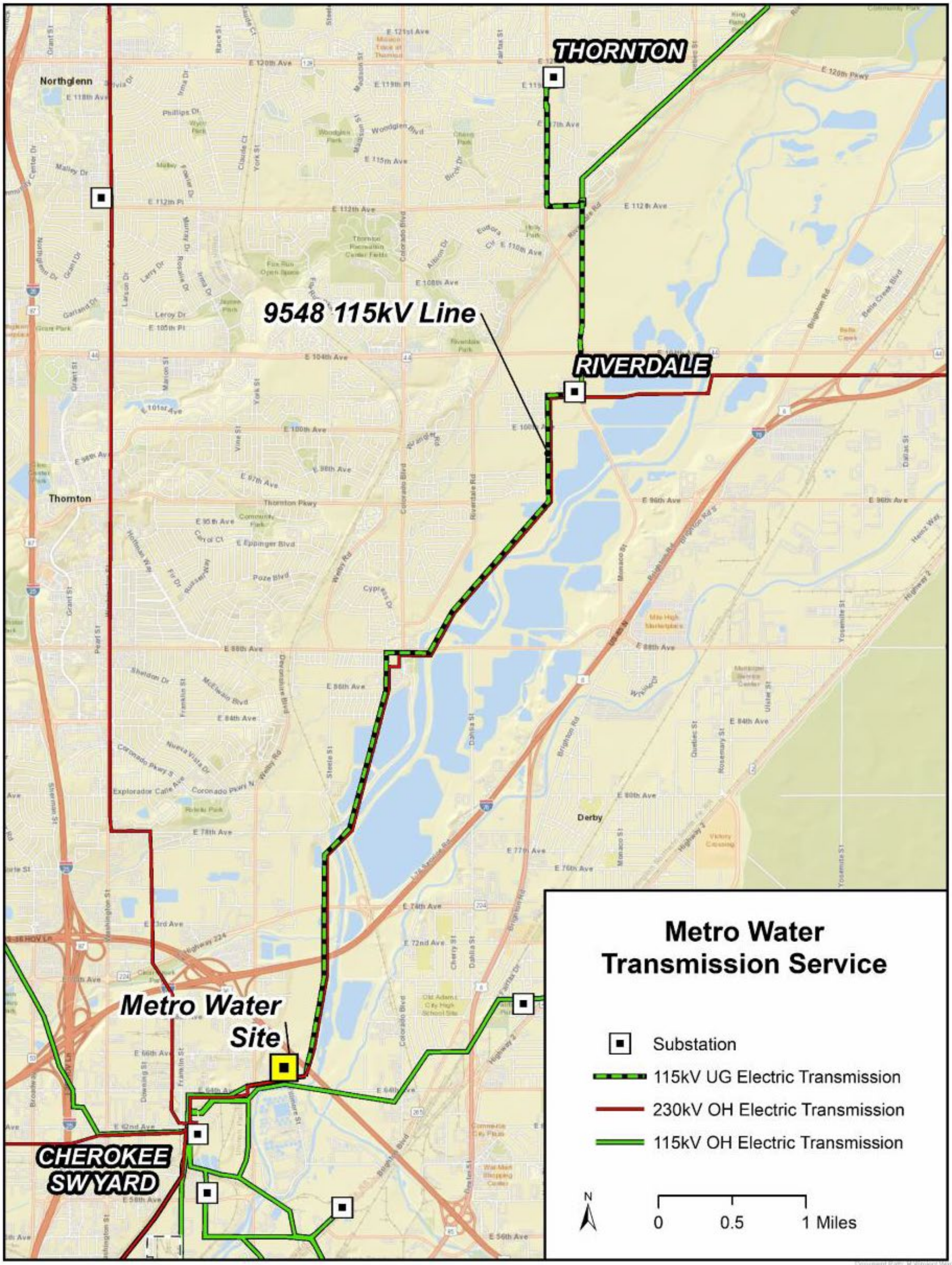
Prudent Avoidance Measures Being Evaluated for Transmission Facilities

The proposed project will be built to meet all prudent avoidance requirements for noise and magnetic fields.

Requested Commission Findings

Public Service requests that the Commission determine that no CPCN is needed as the project is in the ordinary course of business. The total cost of the construction of these transmission facilities will be funded by the customer to whose service they are dedicated. A finding that no CPCN is required for this project is consistent with Commission Rule 3206(b) and will result in procedural and administrative efficiency for a customer that seeks to expand their facilities and operations within Public Service's service territory.

[1] Transmission facilities are typically placed in service before a project is considered "complete," as completion and final closeout of a project includes tasks such as site restoration, decommissioning of assets removed from service, and processing of documentation and final payments that do not directly affect the operation of the facilities.


THORNTON
9548 115kV Line
RIVERDALE
Metro Water Site
CHEROKEE SWYARD
Metro Water Transmission Service
Substation
115kV UG Electric Transmission
230kV OH Electric Transmission
115kV OH Electric Transmission
N
0
0.5
1 Miles

D. TRANSMISSION FACILITIES ASSOCIATED WITH THE IMPLEMENTATION OF THE COLORADO ENERGY PLAN PORTFOLIO IN THE COMPANY'S 2016 ELECTRIC RESOURCE PLAN

In Proceeding No. 16A-0396E, the Commission approved the Preferred Colorado Energy Plan Portfolio ("CEPP") in Phase II of the Company's 2016 Electric Resource Plan ("ERP") by Decision No. C18-0761. The Preferred CEPP included, among other things, the early retirement of Public Service's coal-fired generating units at Comanche 1 and Comanche 2 and the development of approximately 1,800 megawatts ("MW") of new wind and solar generating resources.

The Company initially identified the need for certain transmission investments associated with the Preferred CEPP in the Company's 120-Day Report filed on June 6, 2018 in Proceeding No. 16A-0396E. Specifically, the 120-Day Report contemplated that the following areas of transmission investment would be needed to accommodate the resources that were included in the Preferred CEPP:

1. Voltage Control Devices for the Rush Creek Generator Tie Line ("Gen-Tie") and the Pueblo area;
2. Network Upgrades; and
3. Interconnection Facilities.

On September 30, 2019, Public Service filed an Amendment to its 2016 ERP (Proceeding No. 19A-0530E) to replace two bids originally approved as part of the CEPP after the developer was unable to deliver the projects as bid. The Company issued a 2019 Solar Request for Proposals ("2019 Solar RFP") that specifically targeted replacing the original bids. By Recommended Decision No. R20-0285 (mailed April 23, 2020), the Commission approved a Settlement Agreement directing the Company to acquire the Company's Preferred Replacement Bids or back-up bids pursuant to the detailed terms of the Settlement Agreement. Accordingly, the Company acquired two replacement projects through that solicitation: (1) the Sun Mountain 200 MW solar project, identified as Bid ID 077, and (2) the Front Range – Midway 100 MW solar plus 50 MW storage project, identified as Bid ID 056 (collectively, "Replacement Projects").

The Company conducted transmission studies to identify the facilities needed to interconnect and provide transmission service to the Replacement Projects pursuant to its FERC-approved OATT. The Sun Mountain project's interconnection study identified the facilities needed to interconnect at the Company's existing Comanche Substation in Pueblo County and the Front Range – Midway project's interconnection study identified the facilities needed to interconnect to the Company's existing Midway Substation in El Paso County. The studies associated with the transmission service requests for the Replacement Projects identified that no network upgrades were required to provide transmission service to the Sun Mountain project and the Front Range – Midway project would require two network upgrade projects to provide transmission service: (1) the replacement of a transformer at the Midway Substation, and (2) the upgrade of the Daniels Park – Prairie 230 kV transmission line in Douglas County.

Pursuant to Decision No. C18-0761's directives regarding applications for CPCNs for transmission facilities associated with the CEPP, Public Service intended to efficiently manage the regulatory process by filing a single application for CPCNs for the network upgrades and interconnection transmission projects associated with the Replacement Projects. However, prior to filing this planned application, Public Service learned that the developer of the Front Range – Midway project was experiencing significant challenges in the financing and development of the project that represented a substantial risk that the project would fail. In light of this risk of failure, Public Service elected not to file for approval of the transmission facilities associated with the projects until the risk of project failure was better understood. In late 2022, the developer confirmed that it was unable to meet a critical path project development milestone under the terms of the PPA as the project was not economically viable. Therefore, the Company terminated the PPA in January 2023.

The Company has not yet sought a CPCN for the Sun Mountain interconnection facilities as it seeks a more efficient process to address the scope and cost of transmission facilities associated with the Sun Mountain project. As noted above, while the Company had planned to file a CPCN covering the four transmission projects listed above, the Sun Mountain interconnection facilities' total cost of approximately $1.7 million amounts to less than nine percent of the total cost of the projects included in the planned but unfiled CPCN application for the Replacement Projects transmission facilities.

In place of filing an application for a CPCN for the Sun Mountain, Public Service requests that the Commission determine that no CPCN is needed as the project does not fall within the purview of Rule 3206 as it is normal course of business. Installation of equipment inside an existing substation or switching station, as is the case with the interconnection equipment associated with this project, is an activity that typically occurs in the ordinary course of business pursuant to Public Service's FERC-approved OATT. To the extent the Commission determines a variance is needed from Decision No. C18-0761, Public Service moves the Commission for a variance from Decision No. C18-0761 pursuant to Rule 1003. In such case, pursuant to Rule 1003(c), the Company represents as follows: (I) the variance would be from Paragraph No. 133 of Decision No. C18-0761; (II) the variance would be for a finding that no CPCN is needed for the above-referenced Sun

Mountain interconnection facilities; (III) the request is reasonable and appropriate as the facilities are in the ordinary course of business and the relatively low amount of dollars at stake; and, (IV) the variance would be permanent and full. Below, Public Service provides the information required by Rule 3206 to assist in the Commission's evaluation of this request.

1. SUN MOUNTAIN SOLAR INTERCONNECTION

Project Description and Purpose

The 200 MW Sun Mountain Solar project, identified as Bid ID 077, was one of the two replacement projects selected as part of the 2019 Solar RFP. As it was a replacement project, Sun Mountain was not identified within the Company's 120-Day Report filed in Proceeding No. 16A-0396E, which set forth the results of the 2017 All-Source Solicitation in Phase II of the Company's 2016 ERP.

The Interconnection Facilities needed to interconnect this project were determined as part the Large Generator Interconnection Procedures ("LGIP") pursuant to Attachment N of Xcel Energy's OATT. The LGIP study for Sun Mountain, GI-2021-1, is available on the Company's OASIS website: https://www.rmao.com/public/wtpp/PSCO_Studies.html.

Consistent with the Company's OATT, the LGIP process begins with a customer submitting an Interconnection Request, which includes details surrounding the generation facility and requested service. Upon validating the Interconnection Request, the Company begins the study process with a scoping meeting with the customer. Upon execution of the applicable study agreements, the Company performs reliability studies including steady-state power flow, transient stability, and short circuit analyses. The Company also identifies a list of facilities necessary for the interconnection and a non-binding, good faith cost estimate. The steady-state power flow identifies thermal overloads or voltages outside criteria. The transient stability analysis identifies generator performance and recovery in the short timeframe following a fault on the system. The short circuit analysis identifies circuit breakers unable to clear an expected fault on the system.

Here, the LGIP study identified the specific facilities necessary to interconnect the Sun Mountain solar project. The transmission interconnection facilities include the construction of a new generation interconnection at the Comanche 230 kV Substation located in Pueblo County, including one new 230 kV transmission circuit breaker; relaying for the new circuit breaker and transmission line; dead-end structures and a turning structure for the new transmission line; two spans of transmission line rated at 575 MVA, communication and SCADA for the new interconnection; as well as other supporting materials and equipment, such as foundations, conduit, and cable.

Public Service will construct, own, and operate the interconnection facilities, and will do so in accordance with set forth in accordance with the standards set forth the National Electrical Safety Code ("NESC"), Institute of Electrical and Electronics Engineers ("IEEE"), and Xcel Energy's company standards.

Project Alternatives Considered

There are no feasible alternatives available for this project, as it involves the physical electrical interconnection of a generating facility to Public Service's transmission system. Regarding the type of facilities installed, the equipment to be built at the Comanche Substation is required to interconnect large generation resources like the Sun Mountain project. Evaluation of the interconnection at an alternative location is similarly infeasible because facilities are based on the transmission system location identified by the generation developer in their Interconnection Request pursuant to Public Service's FERC-approved LGIP. Battery storage cannot be deployed as an alternative to the interconnection facilities needed to physically integrate the generation facility to the Public Service transmission system.

Transmission Cost of the Project

$1.7 million (actual).

Date For the Start of Construction of the Project

May 2022

Date Of Completion of the Project

December 2022

In-Service Date of the Project

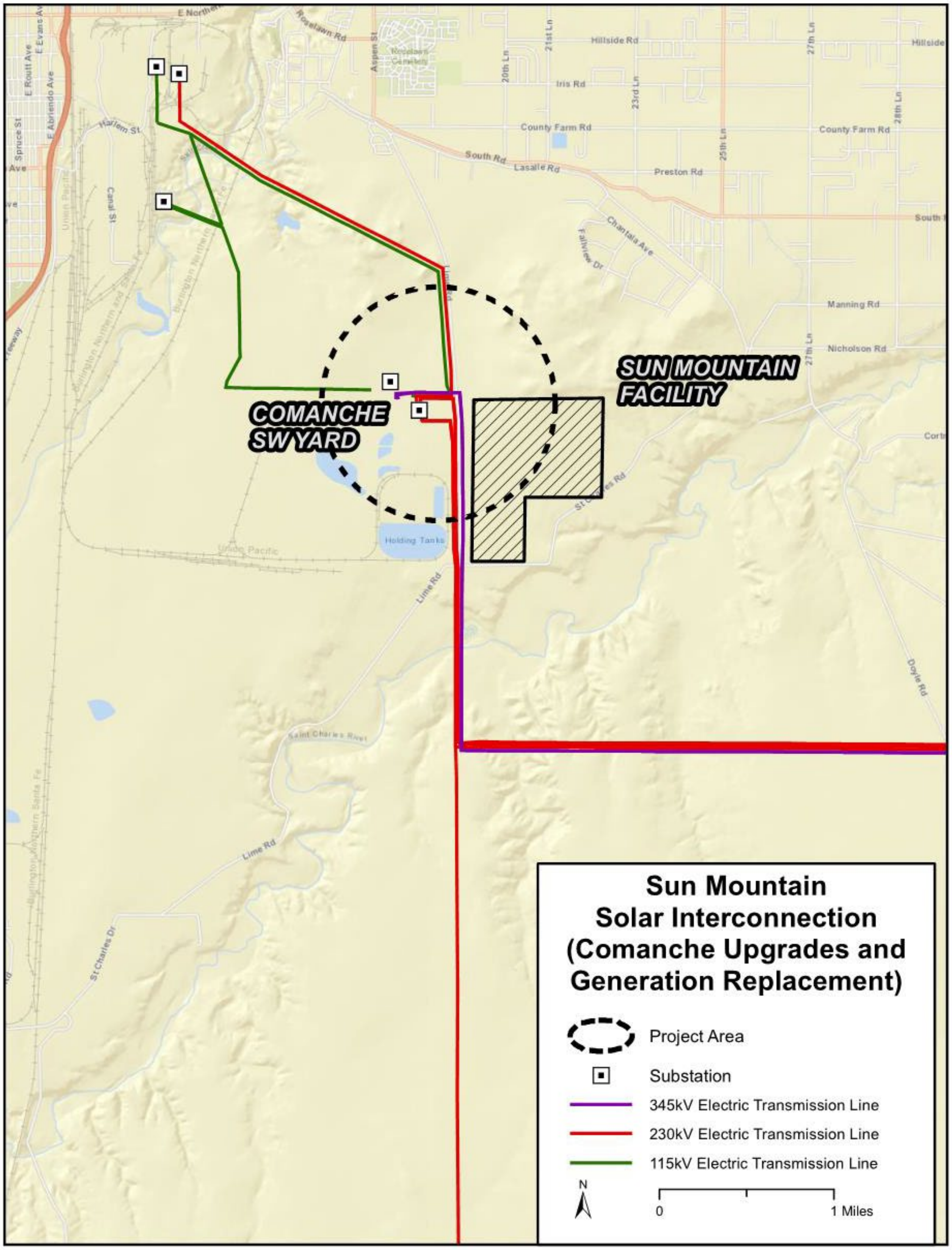
September 2022

General Location

Within the Company's existing Comanche Substation in Pueblo County, Colorado, approximately two miles southeast of the City of Pueblo.

Prudent Avoidance Measures for Transmission Facilities

The proposed project has been built to meet all prudent avoidance requirements for noise and magnetic fields.


SUN MOUNTAIN FACILITY
COMANCHE SW YARD
Holding Tanks
Sun Mountain Solar Interconnection (Comanche Upgrades and Generation Replacement)
Project Area
Substation
345kV Electric Transmission Line
230kV Electric Transmission Line
115kV Electric Transmission Line
N
0
1 Miles

E. STATUS OF PROJECTS LISTED IN PRIOR REPORTS

As indicated in the Introduction, the Transmission Costs reported in the following table are for Transmission facilities only. Dollar figures are reported in millions of dollars.

TBD = To Be Determined

ISD = In-Service Date

Report = Rule 3206 Filing

Table 1 below contains a list of projects that have been identified in past Rule 3206 reports that have been completed/in-serviced or canceled since the Company filed its last Rule 3206 report. No replacement projects have been identified over the past year.

TABLE 1

Projects In-Service, Canceled, or Replaced Since 2022			
Item #	**Project Name**	**Regulatory Approval**	**Final Status**
1	DCP Timnath (Avery) 230/13.8 kV, 28 MVA Distribution Substation	CPCN granted by Decision No. C15-0461 in Proceeding No. 15A0159E.	Project placed In Service 06/2022. Final cost is $12.9.
2	CEPP: Mirasol 230 kV Switching Station	CPCN granted by Decision No. C22-0234 in Proceeding No. 21A-0298E.	Project placed in-service 04/2022. Final cost is $22.3.
3	CEPP: Tundra 345 kV Switching Station	CPCN granted by Decision No. C22-0234 in Proceeding No. 21A-0298E.	Project placed in-service 05/2022. Final cost is $22.1.
4	CEPP: Sun Mountain Solar Interconnection	Refer to Section D above for the discussion of the regulatory approval of the Sun Mountain Solar interconnection facilities.	Project placed in-service 09/2022. Final cost is $1.7.
5	CEPP: Voltage Control Group	CPCN granted by Decision No. C20-0648 in Proceeding No. 19A-0728E.	Project placed in-service 12/2022. Final cost is $67.3
6	CEPP: Front Range Midway Solar Interconnection	N/A	Developer unable to meet critical path milestones and PPA canceled by Public Service.
7	CEPP Transmission Service Network Upgrades associated with the Front Range Midway Solar Interconnection	N/A	Developer unable to meet critical path milestones and PPA canceled by Public Service. The two network upgrade projects identified in the Company's 2022 Report are no longer necessary to provide transmission service for this CEPP project.
8	Glenwood Springs – Rifle 69/115 kV Conversion		The Company has canceled this project as its development is no longer being actively pursued.

Projects In-Service, Canceled, or Replaced Since 2022			
Item #	**Project Name**	**Regulatory Approval**	**Final Status**
9	New Castle 115/69-24.9 kV Substation (Distribution, 16 MVA)	CPCN not required by Decision No. C08-0676 in Case No. 6396.	The Company has canceled this project as its development is no longer being actively pursued.
10	Parachute – Cameo 230 kV Transmission Line	CPCN required by Decision No. C10-0644 in Proceeding No. 10M-206E.	The Company has canceled this project as its development is no longer being actively pursued.
11	Rifle (Ute) – Story Gulch 230 kV Transmission Line Project	CPCN required by Decision No. C10-0644 in Proceeding No. 10M-206E.	The Company has canceled this project as its development is no longer being actively pursued.
12	Vasquez 115/13.8 kV, 28 MVA # 2 Transformer	CPCN not required by Decision No. C15-0590 in Proceeding No. 15M-0043E.	The Company has canceled this project as its development is no longer being actively pursued.
13	Wheeler – Wolf Ranch 230 kV Transmission Project	CPCN not required by Decision No. C14-0732 in Proceeding No. 14M-0061E.	The Company has canceled this project as its development is no longer being actively pursued.
14	Wilson # 1 Sub (Distribution, 115/13.8 kV, 14 MVA)	CPCN not required by Decision No. C10-0644 in Proceeding No. 10M-206E.	The Company has canceled this project as its development is no longer being actively pursued.

Table 2 below contains a comprehensive list of previously planned Transmission projects over the next three years, along with relevant information on each project, including the name, any change in status/cost from the 2022 Rule 3206 Report, project status, and the projected Transmission Costs. The Transmission Costs reported in the following table are for Transmission facilities only and in millions of dollars.

TABLE 2

Projects by In-Service Date						
Item #	**Project Name**	**Change in Status/Cost**	**Regulatory Approval**	**Project Status**	**Transmission Cost Estimate in 2022 Rule 3206 Report ($ million)**	**Current Transmission Cost ($ million) and Estimate Classification**
2023 ISD Projects						
15	CEPP: Greenwood – Denver Terminal 230 kV Transmission	Yes	CPCN granted by Decision No. C20-0648 in Proceeding No. 20A-0063E.	ISD changed from 12/2022 to 7/2023 due to permitting delays. Semi-annual reports containing project status updates are available in Proceeding No. 20A-0063E.	$78	$102 Engineering estimate
16	DCP High Point Distribution Substation 230-13.8 kV	Yes	CPCN granted for transmission and associated distribution facilities by Decision No. R20-0725, exceptions denied by Decision No. C20-0886 in Proceeding No. 20A-0082E.	ISD is 05/2023.	$15	$19 Engineering estimate
17	Bluestone Valley Substation Phase 2 (230kV Expansion)	Yes	CPCN not required by Decision No. C09-0681 and Reaffirmed by Decision No. C21-0312 in Proceeding No. 09M-392E.	ISD changed from 05/2023 to 11/2023 due to outage availability schedule.	$16	$16 Engineering estimate
2024 ISD Projects						
18	DCP Titan (Waterton expansion) Distribution Substation 230/13.8 kV Project	Yes	CPCN granted by Decision No. C18-0427 in Proceeding No. 18A-0199E.	ISD changed from 5/2023 to 5/2024 due to material delays.	$13	$13 Scoping estimate

Projects by In-Service Date						
Item #	**Project Name**	**Change in Status/Cost**	**Regulatory Approval**	**Project Status**	**Transmission Cost Estimate in 2022 Rule 3206 Report ($ million)**	**Current Transmission Cost ($ million) and Estimate Classification**
19	Colorado Springs Utilities Unintended Flow Mitigation Project; (Replaces Monument – Flying Horse Phase Shifting Transformer / Colorado Springs Load Mitigation)	No	CPCN not required by Decision No. C21-0437 in Proceeding No. 21M-0005E.	ISD is 2024.	$12.2	$12.2 Engineering estimate
20	Project Bronco (Kestrel Switching Station)	Yes	CPCN required per Decision No. C22-0438 in Proceeding No. 22A-0005E.	ISD is 2024. The Company's CPCN application is forthcoming.	Customer funded $21.7	Customer funded $28.1 Scoping estimate
2025 ISD Projects						
21	Colorado Power Pathway Segment 2 - Canal Crossing to Goose Creek	No	CPCN granted by Decision Nos. C22-0270 and C22-0430 in Proceeding No. 21A-0096E.	ISD is 2025. Semi-annual reports containing project status updates are available in Proceeding No. 21A-0096E.	$493 (CPCN estimate) $1,700 (all approved segments in 2022 Report)	$490 Appropriation estimate
22	Colorado Power Pathway Segment 3- Goose Creek to May Valley	No	CPCN granted by Decision Nos. C22-0270 and C22-0430 in Proceeding No. 21A-0096E.	ISD is 2025. Semi-annual reports containing project status updates are available in Proceeding No. 21A-0096E.	$206 (CPCN estimate) $1,700 (all approved segments in 2022 Report)	$199 Appropriation estimate
23	Ault – Cloverly 230/115 kV Transmission (Greeley Area Upgrades – Northern)	Yes	CPCN granted by Decision No. R18-0135 in Proceeding No. 17A-0146E.	ISD changed from 12/2023 to 10/2025 due to permitting delays.	$76	$125 Appropriation estimate

Projects by In-Service Date						
Item #	**Project Name**	**Change in Status/Cost**	**Regulatory Approval**	**Project Status**	**Transmission Cost Estimate in 2022 Rule 3206 Report ($ million)**	**Current Transmission Cost ($ million) and Estimate Classification**
2026 ISD Projects						
24	DCP Barker Substation (Distribution, 230/13.8 kV, 50 MVA)	Yes	CPCN not required by Decision No. C10-0644, reaffirmed by Decision No. C21-0437 in Proceeding No. 10M-206E.	A revised cost estimate is currently under development by the Company and has not yet been completed or internally approved. The Company currently expects significantly higher costs on underground directional drilling and overall material and labor increases ISD for Bank #1 is 2/2026. ISD for Bank #2 is 09/2026.	$39.2	TBD – see project status
25	DCP Stock Show (Poder Distribution Substation) 115/13.8kV	Yes	CPCN not required by Decision No. C18-0843 in Proceeding No. 18M-0005E.	ISD is 5/2026.	TBD	$6.6 Scoping estimate
26	Colorado Power Pathway Segment 1- FSV to Canal Crossing	No	CPCN granted by Decision Nos. C22-0270 and C22-0430 in Proceeding No. 21A-0096E.	Semi-annual reports containing project details are available in Proceeding No. 21A-0096E.	$249 (CPCN estimate) $1,700 (all approved segments in 2022 Report)	$243 Scoping estimate
2027 ISD Projects						
27	Colorado Power Pathway Segment 4- May Valley to Tundra	No	CPCN granted by Decision Nos. C22-0270 and C22-0430 in Proceeding No. 21A-0096E.	Semi-annual reports containing project status updates are available in Proceeding No. 21A-0096E.	$380 (CPCN estimate) $1,700 (all approved segments in 2022 Report)	$395 Scoping estimate
28	Colorado Power Pathway Segment 5- Tundra to Harvest Mile	No	CPCN granted by Decision Nos. C22-0270 and C22-0430 in Proceeding No. 21A-0096E.	Semi-annual reports containing project status updates are available in Proceeding No. 21A-0096E.	$367 $1,700 (all approved segments in 2022 Report)	$367 Scoping estimate

Projects by In-Service Date						
Item #	**Project Name**	**Change in Status/Cost**	**Regulatory Approval**	**Project Status**	**Transmission Cost Estimate in 2022 Rule 3206 Report ($ million)**	**Current Transmission Cost ($ million) and Estimate Classification**
29	May Valley-Longhorn Extension (part of Colorado Power Pathway)	No	CPCN conditionally granted by Decision Nos. C22-0270 and C22-0430 in Proceeding No. 21A-0096E.	ISD updated from 12/2025 to 2027 based on the timelines associated with the conditional CPCN and the 2021 ERP & CEP. The Company's initial cost estimate was based on a 2025 ISD. Public Service will present a revised estimate for this project in the 120-Day Report in the 2021 ERP & CEP in the event the Company selects a preferred portfolio that relies on this project.	$ 250	TBD – see project status
30	Gilman – Avon 115 kV Line and 45 MVAR Capacitor Bank at Vail Substation	Yes	CPCN not required by Decision No. C15-0590 in Proceeding No. 15M-0043E.	ISD updated from 12/2024 to 6/2027 to coordinate timing with Holy Cross Electric. While the Company is still pursuing the development of this project, transmission costs are now listed as TBD as the Company has not yet completed or internally approved a revised estimate for the cost of this project.	$11.4	TBD – see project status

Projects by In-Service Date						
Item #	**Project Name**	**Change in Status/Cost**	**Regulatory Approval**	**Project Status**	**Transmission Cost Estimate in 2022 Rule 3206 Report ($ million)**	**Current Transmission Cost ($ million) and Estimate Classification**
31	Climax-Robinson Rack-Gilman 115 kV Transmission	Yes	CPCN not required by Decision No. C19-0638 in Proceeding No. 19M-0005E.	ISD changed from 2024 to 2027 due to permitting delays. While the Company is still pursuing the development of this project, transmission costs are now listed as TBD as the Company has not yet completed or internally approved a revised estimate for the cost of this project.	$15	TBD – see project status
ISD To Be Determined						
32	Weld – Ennis 230/115 kV Transmission Project (Greeley Upgrades – Southern)	Yes	CPCN required by Decision No. C20-0477 in Proceeding No. 20M-005E.	This project is currently being evaluated by the Colorado Coordinated Planning Group Northeast Colorado Subcommittee and the Company anticipates filing a CPCN once the scope of the project is finalized. The Company is unable to provide a revised estimate of cost until the scope of the project is finalized. Targeted ISD is also TBD based on scope reevaluation.	$98	TBD – see project status
33	DCP Dove Valley Distribution Substation 115/13.8 kV	Yes	CPCN not required by Decision No. C18-0843 in Proceeding No. 18M-0005E.	ISD is TBD. The project is under review and the Company will update the Commission as appropriate in the future.	TBD	TBD – see project status

F. PROJECTS PRESENTED FOR COMMISSION INFORMATIONAL PURPOSES

These conceptual projects have not been sufficiently developed by the Company to present a project scope and cost estimate to the Commission as planned projects but could become planned projects prior to the Company making its next Rule 3206 filing. The Company will file amended or supplemental reports pursuant to Rule 3206 as necessary when a conceptual project becomes sufficiently defined to become a planned project.

1. LONG RANGE DISTRIBUTION PLANNING SUBSTATION PROJECTS

Public Service, Staff, and the UCA agreed in Proceeding No. 14A-1002E that the Company would identify potential new distribution substation sites in rapidly growing areas as part of this report. Below is a preliminary list of conceptual new substation projects under consideration by the Company. This is provided for informational purposes only, and at this time Public Service is not seeking a Commission determination of the need for CPCNs for these projects. Because they are conceptual, in-service dates on these projects are TBD.

Long Range Distribution Planning Substation Projects			
Item #	**Substation Project Name**	**Type**	**Approximate Location**
34	Superior	115 kV/13.8 kV	Town of Superior
35	Sandy Creek	230 kV/13.8 kV	Arapahoe County, near future Sandy Creek development

Based on the 2022 expiration of the agreement between the Company, Staff, and UCA that led to the Company's inclusion of this information in the annual Rule 3206 Reports and because of the Commission's recent implementation of distribution system planning regulations through Rule 3525, et seq., the Company intends to work with Staff and UCA to continue reporting on this topic in an alternative forum and plans to discontinue reporting on long-range distribution planning substation projects through its annual Rule 3206 Report beginning in 2024.

2. 2021 ELECTRIC RESOURCE PLAN AND CLEAN ENERGY PLAN

Over the next several years, Public Service plans to study and move forward with a number of other transmission projects that are currently only in conceptual stages. These conceptual projects are projects that, while the need for enhancements to the transmission system has been identified, the Company has not yet completed sufficient study or evaluation to internally approve a project scope or cost estimate through the

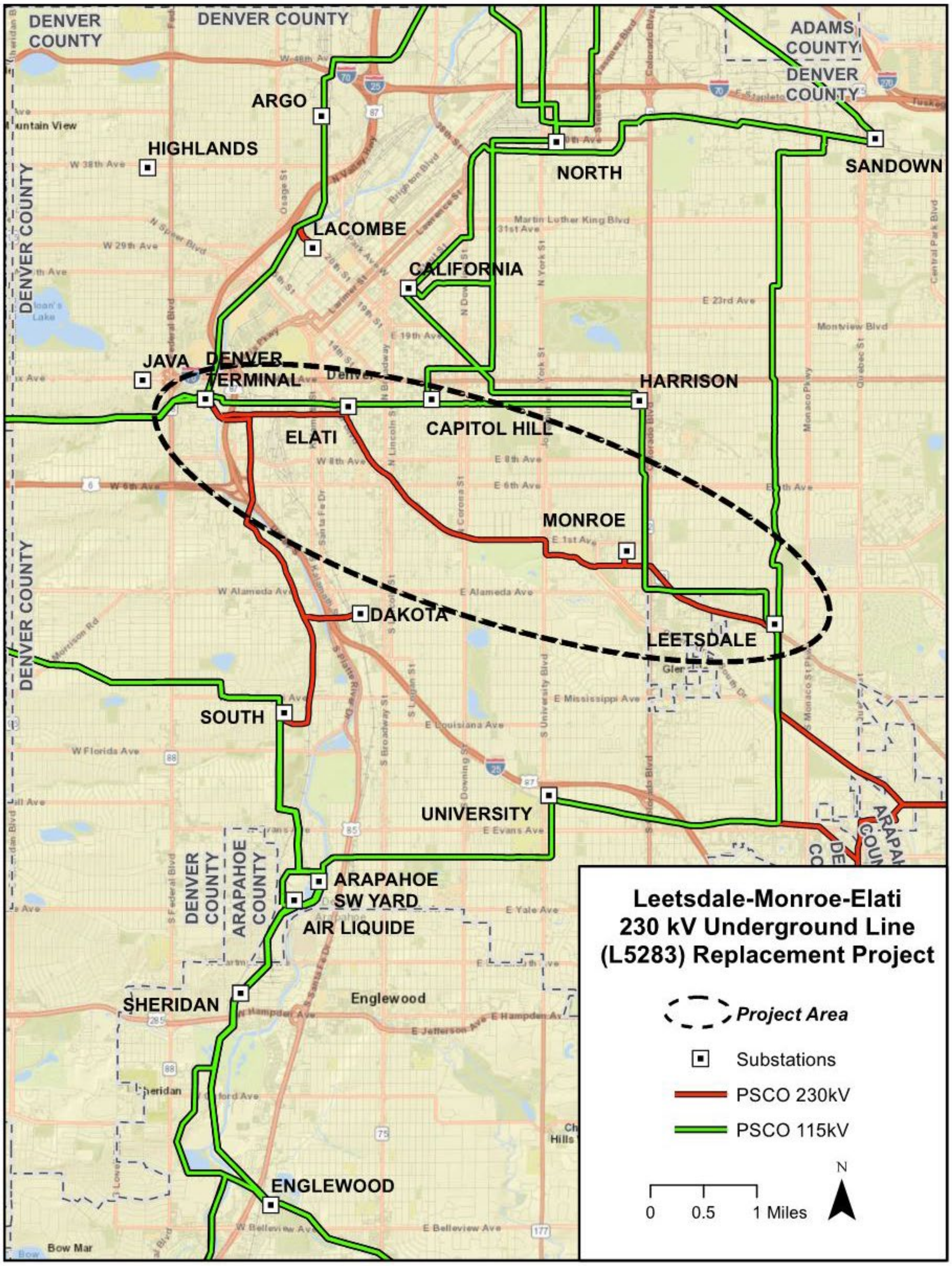
Company's PLC. The most notable conceptual projects are the categories of projects that will be needed to reliably interconnect and provide transmission service to the generation portfolio acquired through the Company's 2021 ERP & CEP in Proceeding No. 21A-0141E. These projects, along with the transmission study process and procedural process the Company expects to follow were discussed in more detail in the Direct Testimony of Mr. Hari Singh filed in that proceeding, as well as the Direct Testimony of Ms. Amanda R. King filed in Proceeding No. 21A-0096E.

As indicated in those proceedings, as Public Service looks to unlock new generation resources in more remote areas of the State the Company anticipates needing to make additional transmission investment in the following four categories: (1) Denver Metro area network upgrades, (2) grid (strength) reinforcement, (3) reactive/voltage support, and (4) generation interconnection facilities. Once the final resource portfolio is approved by the Commission in Phase II of the 2021 ERP & CEP, the Company will perform more detailed planning studies and begin to conduct generator interconnection studies. While the full scope of the facilities and costs for these categories of transmission investment cannot be developed until a generation portfolio is approved in Phase II of the 2021 ERP & CEP, the Company has begun to evaluate potential transmission projects that it expects to be driven by these acquisitions. To date, Public Service has identified one Denver Metro network upgrade that, while still conceptual in nature, will be needed to maintain current system reliability and to implement the resource portfolio acquired in the 2021 ERP & CEP.

The underground Leetsdale – Monroe – Elati 230 kV transmission line (Circuit 5283) was derated in 2022 based on a facility rating update study for the circuit. Because of the substantial derate (>20%), the line frequently experiences post-contingency (N-1) overloads under certain system operating conditions and is a transmission capacity constraint (i.e. congestion) for higher renewable generation imports in the Denver Metro area. The line derate will become an even more challenging transmission congestion problem with higher renewable generation imports into the Denver Metro area from the 2021 ERP & CEP and the scheduled retirement of the Cherokee 4 generator in 2027. A transmission project is necessary to mitigate existing, as well as expected future, transmission congestion challenges.

Public Service's preliminary analysis has identified that upgrading the existing oil-filled cable used on this circuit with a new cross-linked polyethylene ("XLPE") cable would alleviate overloads of the circuit. Because of the location of the Leetsdale – Monroe – Elati 230 kV transmission line in central Denver, the Company's alternatives to address the overload of this circuit are limited due to urban congestion, or lack of available space, within the Denver Metro area. There is limited space in which the Company can develop new lines that address overloading of this circuit. Any such line will likely be required to be constructed underground. Furthermore, the Company is skeptical that an energy storage solution could address the reliability issues associated with an overload on this circuit given the operational constraints of currently available storage technologies and the nature of the overloads that this circuit will experience. However, in order to ensure that the Company identifies the most appropriate solution to address the need for this project, Public Service is conducting more detailed evaluations of the potential for applications of energy storage or advanced transmission technologies to reliably and cost-effectively address the overload of this circuit in place of part (or all) of the identified upgrade project. The Company anticipates filing an application for a CPCN before the end of 2023 for a project which addresses this circuit and will allow for the expeditious development and construction of a solution aligned with resource acquisition timelines in the 2021 ERP & CEP.

The Company will continue to evaluate transmission projects necessary to accommodate the resource portfolio under development in the 2021 ERP & CEP Phase II process. In the Phase I Decision, Decision No. C22-0459, the Company was directed to provide a project-level analysis for transmission costs associated with the investments needed to implement the resource portfolio. However, as the Commission recognized, the time pressure of the Phase II process and market uncertainties affect the accuracy of the estimates that the Company is able to develop in the 120-Day Report. As these studies and specific facilities become more refined, the Company will update the Commission through appropriate filings, including in the 120-Day Report in the 2021 ERP & CEP, future Rule 3206 filings or amended filings, applications for CPCNs for these transmission facilities, and elsewhere as appropriate.


Leetsdale-Monroe-Elati
230 kV Underground Line
(L5283) Replacement Project
Project Area
Substations
PSCO 230kV
PSCO 115kV
0 0.5 1 Miles
N
DENVER COUNTY
ADAMS COUNTY
ARAPAHOE COUNTY
ARGO
HIGHLANDS
NORTH
SANDOWN
LACOMBE
CALIFORNIA
JAVA
DENVER TERMINAL
HARRISON
ELATI
CAPITOL HILL
MONROE
DAKOTA
LEETSDALE
SOUTH
UNIVERSITY
ARAPAHOE SW YARD
AIR LIQUIDE
SHERIDAN
ENGLEWOOD
Englewood